CANADA

National Energy Board

Reasons for Decision

BP Resources Canada Limited

FSC Resources Limited, Saranac Power Partners L.P., and Shell Canada Limited

Kamine Beaver Falls Cogen Co., Inc., as managing general partner of Kamine/Besicorp Beaver Falls L.P.

Kamine Syracuse Cogen Co., Inc., as managing general partner of Kamine/Besicorp Syracuse L.P.

Western Gas Marketing Limited

GH-5-92

December 1992

Gas Exports

National Energy Board

Reasons for Decision

IN THE MATTER OF

BP Resources Canada Limited

Kamine Beaver Falls Cogen Co., Inc., as managing general partner of Kamine/Besicorp Beaver Falls L.P.

Kamine Syracuse Cogen Co., Inc., as managing general partner of Kamine/Besicorp Syracuse L.P.

Western Gas Marketing Limited

Applications Pursuant to Part VI of the *National Energy Board Act* for Licences to Export Natural Gas and,

FSC Resources Limited, Saranac Power Partners L.P., and Shell Canada Limited

Application Pursuant to Parts I and VI of the *National Energy Board Act* for the Transfer of a Licence to Export Natural Gas or, alternatively, for a Licence to Export Natural Gas

GH-5-92

December 1992

Gas Exports

Cat. No. NE22-1/1992-18E
ISBN 0-662-20247-3

This report is published separately in both official languages.

Ce rapport est publié séparément dans les deux langues officielles.

Copies are available from:

Regulatory Support Office
National Energy Board
311 Sixth Avenue S.W.
Calgary, Alberta
Canada
T2P 3H2
(403)292-4800

Exemplaires disponibles auprès du:

Bureau du soutien de la réglementation
Office national de l'énergie
311, 6e Avenue s,-o.
Calgary (Alberta)
Canada
T2P 3H2
(403)292-4800

Printed in Canada

Imprimé au Canada

Recital and Appearances

IN THE MATTER OF the *National Energy Board Act* and the regulations made thereunder;

AND IN THE MATTER OF applications under Part VI of the *National Energy Board Act* for new licences to export natural gas by:

BP Resources Canada Limited; Kamine Beaver Falls Cogen Co., Inc., as managing general partner of Kamine/Besicorp Beaver Falls L.P.; Kamine Syracuse Cogen Co., Inc., as managing general partner of Kamine/Besicorp Syracuse L.P.; and Western Gas Marketing Limited;

AND IN THE MATTER OF an application under Parts I and VI of the *National Energy Board Act* for the transfer of a licence to export natural gas or, alternatively, for a new licence to export natural gas by:

FSC Resources Limited, Saranac Power Partners L.P., and Shell Canada Limited;

AND IN THE MATTER OF Hearing Order GH-5-92;

HEARD in Calgary, Alberta on 25 and 26 August 1992.

BEFORE:

R. Illing	Presiding Member
A.B. Gilmour	Member
C. Bélanger	Member

APPEARANCES:

D.A. Holgate	BP Resources Canada Limited
S.H. Lockwood E.S. Decter	FSC Resources Limited, Saranac Power Partners L.P., and Shell Canada Limited
D.A. Holgate	Kamine Beaver Falls Cogen Co., Inc., as managing general partner of Kamine/Besicorp Beaver Falls L.P.
D.A. Holgate	Kamine Syracuse Cogen Co., Inc., as managing general partner of Kamine/Besicorp Syracuse L.P.
M.J. Samuel	Western Gas Marketing Limited
L. Keough	North Canadian Oils Limited

R.B. Hillary	Paramount Resources Limited
E.P. Varga	TransCanada PipeLines Limited
W.M. Moreland	Alberta Petroleum Marketing Commission
M.A. Fowke L.A. Boychuk	National Energy Board

Table of Contents

List of Tables

List of Figures

List of Appendices

Abbreviations

ACQ	Annual Contract Quantity
Act	*National Energy Board Act*
Agreements	the two natural gas purchase agreements executed between Kamine and NCM
ANR	ANR Pipeline Company
APMC	Alberta Petroleum Marketing Commission
BASF	BASF Corporation
BCEMPR	British Columbia Ministry of Energy, Mines and Petroleum Resources
Bcf	billion cubic feet
Board	National Energy Board
BP	BP Resources Canada Limited
BPOI	BP Exploration and Oil Inc.
Cascade	Cascade Natural Gas Corporation
CNG	CNG Transmission Company
DCQ	Daily Contract Quantity
DOE/FE	(United States of America) Department of Energy, Office of Fossil Energy
EARP Guidelines Order	*Environmental Assessment and Review Process Guidelines Order*
EIA	Export Impact Assessment
El Paso	El Paso Natural Gas Co.
Empire	Empire State Pipeline
ERCB	Alberta Energy Resources Conservation Board
FERC	(United States of America) Federal Energy Regulatory Commission

FS	Firm Service
FSC	FSC Resources Limited
GH-1-92	Hearing Order GH-1-92 in respect of various applications for natural gas export licences; Reasons for Decision dated October 1992
GH-3-91	Hearing Order GH-3-91 in respect of various applications for natural gas export licences; Reasons for Decision dated October 1991
GH-5-89	Hearing Order GH-5-89 in respect of TransCanada's application for 1991 and 1992 facilites and various applications for natural gas export licences; Reasons for Decision dated April 1991
GH-6-89	Hearing Order GH-6-89 in respect of various applications for natural gas export licences; Reasons for Decision dated July 1990
GHR-1-92	Hearing Order GH-R-1-92 in respect of a review of TransCanada's application for the Blackhorse Extension; Reasons for Decision dated June 1992
GIC	Gas Inventory Charge
GJ	gigajoule(s)
GLGT	Great Lakes Gas Transmission Limited Partnership
G-P	Georgia-Pacific Corporation
Hadson	Hadson Power Partners of Rensselaer
Hydro Québec decision	the Federal Court of Appeal decision in the case of *Attorney General of Québec* v. *National Energy Board* [1991] 3 F.C. 443
Inside F.E.R.C.	*Inside F.E.R.C.'s Gas Market Report*
Iroquois	Iroquois Gas Transmission System, L.P.
Joint Applicants	FSC, Saranac and Shell
Kamine	Kamine Beaver Falls and Kamine Syracuse
Kamine Beaver Falls	Kamine Beaver Falls Cogen Co., Inc. as managing general partner of Kamine/Besicorp Beaver Falls L.P.

Kamine Natural Dam	Kamine Natural Dam Cogen Co., Inc. as managing general partner of Kamine/Besicorp Natural Dam L.P.
Kamine Syracuse	Kamine Syracuse Cogen Co., Inc. as managing general partner of Kamine/Besicorp Syracuse L.P.
kW.h	kilowatt hour (1000 watt hours)
LDC	local distribution company
MAQ	Minimum Annual Quantity
MDQ	Maximum Daily Quantity
MichCon	Michigan Consolidated Gas Company
MMBtu	million British thermal units
MMcf	million cubic feet
MW	megawatt (1000 kilowatts)
MW.h	megawatt hour (1000 kW.h)
National Fuel	National Fuel Gas Supply Corporation
NEB	National Energy Board
NCM	North Canadian Marketing Inc.
NCO	North Canadian Oils Limited
NGPL	Natural Gas Pipeline Company of America
Niagara Mohawk	Niagara Mohawk Power Corporation
North Country	North Country Gas Pipeline Corporation
NOVA	NOVA Corporation of Alberta
NYPA	New York Power Authority
NYPSC	New York Public Service Commission
NYSEG	New York State Electric & Gas Corporation
NYSF	New York State Fair

Part VI Regulations	*National Energy Board Part VI Regulations*
Puget	Puget Sound Power & Light Company
PURPA	(United States of America) Public Utility Regulatory Policies Act
QF	qualifying cogeneration facility
RR/P	remaining reserves to production ratio
San Juan agreement	gas sales agreement between BP, Tenaska and TWP
Saranac	Saranac Power Partners, L.P.
SEM	Saskatchewan Energy and Mines
Shell	Shell Canada Limited
SPI	Specialty Paperboard Inc.
St. Lawrence Gas	St. Lawrence Gas Company Inc.
Sumas agreement	gas sales agreement between BP, Tenaska and TWP
Tenaska	Tenaska Gas Co.
TransCanada	TransCanada PipeLines Limited
TransGas	TransGas Limited
TWP	Tenaska Washington Partners, L.P.
U.S.	United States of America
Westcoast	Westcoast Energy Inc.
Western Gas	Western Gas Marketing Limited

Chapter 1

Part VI — Gas Export Licence Applications

1.1 The Applications

During the GH-5-92 proceeding, the National Energy Board ("the Board" or "NEB") examined six applications for gas export licences and one application for the transfer of a gas export licence or, alternatively, for a new gas export licence. The following applications were filed:

1. BP Resources Canada Limited ("BP");

2. FSC Resources Limited ("FSC"), Saranac Power Partners, L.P. ("Saranac") and Shell Canada Limited ("Shell") for the transfer of GL-138 or, alternatively, for a new gas export licence;

3. Kamine Beaver Falls Cogen Co., Inc., as managing general partner of Kamine/Besicorp Beaver Falls L.P. ("Kamine Beaver Falls");

4. Kamine Syracuse Cogen Co., Inc., as managing general partner of Kamine/Besicorp Syracuse L.P. ("Kamine Syracuse");

5. Western Gas Marketing Limited ("Western Gas") for export to Hadson Power Partners of Rensselaer ("Hadson");

6. Western Gas for export to Michigan Consolidated Gas Company ("MichCon"); and,

7. Western Gas for export to Natural Gas Pipeline Company of America ("NGPL").

Table 1-1 provides a summary of each export licence application reviewed during the GH-5-92 proceeding.

Table 1-1

Summary of Applied-for Licences

GH-5-92

Application	**Buyer (Type of market)**	**Term**	**Export Point**	**Maximum Quantities Applied For** Daily 10^3m^3 (MMcf)	Annual 10^6m^3 (Bcf)	Term 10^6m^3 (Bcf)
1. BP	Tenaska (cogen. plant)	1 Oct. 1993 to 31 Dec. 2011 (or 17 years)	Huntingdon, British Columbia	504.1 (17.8)	184.0 (6.5)	3128.0 (110.4)
2. FSC/Sananac/ Shell	Saranac (cogen. plant)	15 years from date of 1st del.	Napierville, Québec	1445.0 (51.0)	529.0 (18.7)	7125.0 (251.5)
3. Kamine Beaver Falls	Kamine (cogen. plant)	1 Nov. 1993 to 31 Oct. 2008	Iroquois, Ontario	456.1 (16.1)	167.1 (5.9)	2494.9 (88.1)
4. Kamine Syracuse	Kamine (cogen. plant)	1 Nov. 1993 to 31 Oct. 2008	Chippawa, Ontario	461.7 (16.3)	168.5 (5.9)	2506.8 (88.5)
5. Western Gas	Hadson (cogen. plant)	15 years from date of 1st del.	Niagara Falls, Ontario	509.9 (18.0)	186.6 (6.6)	2800.0 (98.8)
6. Western Gas	MichCon (system supply)	1 June 1992 to 31 Oct. 1996	Emerson, Manitoba	906.5 (32.0)	331.8 (11.7)	1466.0 (51.7)
7. Western Gas	NGPL (system supply)	1 June 1992 to 31 Oct. 2000	Emerson, Manitoba	4853.0 (171.3)	1776.0 (62.7)	14930.0 (527.0)

1.2 Market-Based Procedure

The Board, in considering an export application, must take into account section 118 of the *National Energy Board Act* ("the Act"), which requires that the Board have regard to all considerations that appear to it to be relevant and, in particular, that the Board satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for reasonably foreseeable Canadian requirements, taking account of trends in discovery.

To comply with the requirements of section 118 of the Act, the Board utilizes its Market-Based Procedure. After the issuance of Hearing Order GH-5-92, the Board released its May 1992 Reasons for Decision - *Proposed Changes to the Application of the Market-Based Procedure* (GHW-1-91). In a letter dated 24 July 1992, the Board advised Interested Parties to GH-5-92 that for the purposes of the GH-5-92 proceeding, the Board would be relying on the May 1992 Market-Based Procedure. The following discussion of the Board's Market-Based Procedure is general in nature and applies to each application heard in the GH-5-92 proceeding.

The Market-Based Procedure provides that the Board consider:

- complaints, if any, under the Complaints Procedure;
- an Export Impact Assessment ("EIA"); and
- any other factors that the Board considers relevant to its determination of the public interest.

1.2.1 Complaints Procedure

When an application for an export licence is filed with the Board, interested parties have an opportunity to examine the various elements of the proposal. It is open to a Canadian purchaser of natural gas to object to the export by filing a complaint if it believes that it has not been able to purchase gas on terms and conditions similar to those contained in a gas export sales contract. There were no complaints made with respect to the applications for export licences in the GH-5-92 proceeding.

1.2.2 Export Impact Assessment

The purpose of the EIA is to assist the Board in determining whether a proposed export is likely to cause Canadians difficulty in meeting their future energy requirements at fair market prices. When the Market-Based Procedure was first introduced, each export applicant was required to file an EIA assessing the impact of the proposed export on domestic natural gas supply, demand, and prices, and on the ability of Canadian energy markets to adjust to these changes without difficulty.
In a review of EIA filing requirements conducted in the fall of 1989, the Board decided that, while it would retain the EIA as part of its Market-Based Procedure, it would conduct its own non-project-specific assessment. Each applicant now has the option of using the Board's most recent analysis or of preparing and submitting its own analysis as a basis for assessing whether the proposed exports would result in adjustment difficulties in Canadian energy markets.

All applicants in this hearing adopted the Board's EIA.

Based on its EIA, the Board believes that the applied-for export volumes would have little impact on the production, consumption and price of gas in Canada, and that Canadian energy users would not experience difficulty in meeting their future energy requirements as a result of the proposed exports. The Board is also of the view that Canadian buyers of natural gas would not have significant problems adjusting to market forces that would result from approval of these exports.

1.2.3 Other Factors Relevant to the Public Interest

In addition to using the Complaints Procedure and the EIA to ascertain whether gas proposed to be exported is surplus, the Board continues, as required by section 118 of the Act, to have regard to all other factors it considers relevant in determining whether a proposed export is in the public interest. In general, these factors can be placed into two categories: (a) gas supply and (b) market, commercial arrangements and regulatory status. This listing of factors that the Board may regard as relevant is illustrative rather than exhaustive, but the Board relies heavily on information filed by export licence applicants in accordance with the *National Energy Board Part VI Regulations* ("Part VI Regulations"). This information is used to assess whether an export proposal is in the public interest. The onus is on each applicant to ensure that the filed material is such as to persuade the Board that the project has substance and is at a sufficiently advanced stage of completion to warrant the issuance of a licence.

1.2.3.1 Gas Supply

The Board conducts a review of each applicant's gas supply arrangements to assist it in determining whether the proposed exports are in the public interest. In its assessment of gas supply, the Board examines the contractual arrangements pertaining to supply, the adequacy of both reserves and productive capacity to support the applied-for export, and the status of provincial removal authorizations.

The Board, in its GHW-1-91 decision, confirmed its view that examination of the full details of the gas supply arrangements is an important component of its determination of whether proposed exports are in the national public interest. The Board normally expects applicants to demonstrate that established reserves are equal to or exceed the applied-for volume and that productive capacity will be adequate to meet the proposed annual export volumes over the majority of the applied-for licence term. The Board, however, has been, and will continue to be, flexible in exercising its judgement in assessing project-specific supply.

Each applicant is required to provide an estimate of remaining established reserves for those fields from which it intends to produce gas for the proposed export. The Board conducts geological and engineering analyses of each applicant's gas supply in order to prepare its own estimate of the applicant's marketable gas reserves.

In its evaluation of gas reserves, the Board makes use of its gas reserves database, which is maintained on an ongoing basis. The evaluation of gas reserves includes a nomenclature check for correlation purposes, volumetric studies of new pools, re-examination of developing pools and performance analysis of producing pools. A review and an assessment of the ownership and contractual status of all pools included in the applications are also done.

The Board's estimate of reserves, along with basic deliverability data for each pool for which estimates of reserves were submitted, are used in preparing productive capacity projections. Productive capacity projections are generally adjusted to reflect an applicant's expected requirements for gas. The adjusted productive capacity is the estimated productive capacity at any point in time, carrying forward for future use the productive capacity resulting from an earlier excess of productive capacity over production. The requirements shown in the productive capacity figures are based on a load factor of 100 percent and may therefore somewhat overstate each applicant's actual supply requirements. To the extent that a lower load factor was anticipated, productive capacity would be sustained beyond the time the Board's analysis indicates.

1.2.3.2 Market, Commercial Arrangements and Regulatory Status

The Board conducts a review of the market, commercial arrangements and regulatory status underpinning projects to assist it in determining whether the proposed exports are in the public interest. The applications dealt with in GH-5-92 were for sales to two types of end-use markets: sales for system supply and sales to cogeneration facilities. The Board's review of these market types included consideration of the following for each market type:

- for exports for system supply, it included consideration of the purchaser's current and projected requirements and supply portfolio with a view to determining the need for and the role of the Canadian gas supply within that portfolio; and,

- for exports to a cogeneration facility, defined as a facility that produces electricity and thermal energy for use in commercial or industrial operations, an examination of the contractual chain, from the gas sales contract to the power and thermal sales contracts, was conducted. In this regard, the Board looked to the status of project financing, construction schedules and qualifying cogeneration facility ("QF") certification under the Public Utility Regulatory Policies Act ("PURPA") of the U.S. Federal Energy Regulatory Commission ("FERC").

For each type of end-use market, the review included consideration of, among other items, the load factors at which the proposed exports are expected to flow and the status of pertinent regulatory authorizations in Canada and the U.S.

The Board's review of the commercial arrangements included consideration of information each applicant was required to file in accordance with the Part VI Regulations and in response to Board information requests issued during the proceeding. This information included the following:

- the status of upstream and downstream transportation arrangements, including all transportation contracts, either in final form or as precedent agreements;

- the contractual obligations between the Canadian sellers and the U.S. buyers, including executed gas sales contracts;

- any resale arrangements that occur beyond the international boundary sale point, where such arrangements have a direct effect on the international sales agreement, including filing of these downstream contracts; and

- for cogeneration facilities, the contractual obligations between the cogeneration facility and the electric utility and the steam host.

In its review of the gas sales contracts between the Canadian sellers and the U.S. buyers, the Board made the following determinations:

- whether the contracts are likely to recover associated Canadian intraprovincial and interprovincial transportation costs;
- whether the contracts contain provisions which permit adjustments to reflect changing market conditions over the life of the contract;
- whether the export sales contract is durable;
- whether the contracts ensure that the volumes contracted for are likely to be taken;
- whether the contracts have the support of the Canadian producer(s) supplying the gas to the export project; and,
- whether the requested licence term is appropriate.

With respect to the second of the factors listed above, that of contractual responsiveness to changing market conditions, the Board recognizes that there may be cases where contracts are attractive to the parties involved, notwithstanding a lack of flexibility. In implementing the criterion relating to contract responsiveness, the Board operates on the presumption that, where contracts are freely negotiated at arm's length, they are in the public as well as the private interest.

1.3 Sunset Clauses

It has generally been Board practice in issuing a gas export licence to set an initial term of the licence for a short period of time during which, if the export of gas commences, the licence becomes effective for the full period approved by the Board. This condition in the licence is referred to as a sunset clause because the licence would expire if exports had not commenced within a specified timeframe. Inclusion of the sunset clause is intended to limit outstanding licences to those for which the gas actually flows within a reasonable period after the decision. The Board questioned each applicant concerning the acceptability of a sunset clause in the applied-for licence and in each case the applicant indicated that the inclusion of a sunset clause would be acceptable.

1.4 Environmental Screening

On 8 February 1990, the Minister of Energy, Mines and Resources, the Honourable Jake Epp, wrote to the Board requesting clarification on how the Board complied or would comply with the *Environmental Assessment and Review Process Guidelines Order* (the "EARP Guidelines Order") in arriving at its decision to issue licences for the export of natural gas. In his response to the Minister, the Chairman of the Board advised that, in compliance with the EARP Guidelines Order, the Board would be instituting a screening procedure to examine the potential environmental effects of each export proposal before the Board.

The Board performed a screening, pursuant to Hearing Order GH-5-92 and the EARP Guidelines Order, wherein it considered submissions from each applicant.

On 9 July 1991, the Federal Court of Appeal issued its decision in the case of *Attorney General of Québec* v. *National Energy Board* [1991] 3 F.C. 443 (the "Hydro-Québec decision"). The Court held that the Board's jurisdiction over exports (in this case, electricity exports) did not extend to the facilities used for the production of the good for export. Accordingly, as was stated by Mr. Justice Marceau, speaking on behalf of the Court (at page 450):[4]

> "The factors which may be relevant in considering an application for leave to export electricity and the conditions which the Board may place on its leave clearly cannot relate to anything but the export of electricity."

The Board is of the view that the Hydro-Québec decision applies to the regulation of gas exports as well as electricity exports.

Each applicant filed with the Board information concerning the potential environmental effects, and the social effects directly related to those environmental effects, that would be caused by the exportation of gas from Canada. All interested parties were served with these written submissions.

The Board, by means of a screening pursuant to the EARP Guidelines Order, has concluded that the three applications of Western Gas fall within the ambit of Note 3 of the Board's EARP Guidelines Order List of Automatic Exclusions (no new pipeline facilities are required) and therefore require no further examination. For the remaining applications, the Board has completed its environmental screening and has concluded that there are no potentially adverse environmental effects associated with the issuance of the export licences to the applicants.

---

4 On 11 June 1992, Leave to Appeal the Hydro-Québec decision was granted to the Grand Council of Crees of Québec by the Supreme Court of Canada.

Chapter 2

BP Resources Canada Limited

2.1 Application Summary

By application dated 1 April 1992, BP Resources Canada Limited sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	-	commencing 1 October 1993 or as soon thereafter as pipeline facilities are available and the cogeneration plant commences full operation, and extending until 31 December 2011 or 17 years, whichever is earlier	
Point of Export	-	Huntingdon, British Columbia	
Maximum Daily Quantity	-	504.14 10^3m^3	(17.8 MMcf)
Maximum Annual Quantity	-	184 10^6m^3	(6.5 Bcf)
Maximum Term Quantity	-	3 128 10^6m^3	(110.4 Bcf)
Tolerances	-	10 percent per day and 2 percent per year	
	-	adjustments due to variations in the actual heating conversion factor of 38.62 MJ/m^3 at Huntingdon, B.C.	

BP also requested that the date contained in the sunset clause of the export licence be 29 January 1996. This coincides with the expiration of a cure period in the gas sales contract which allows the commercial start-up date to be extended 90 days beyond 31 October 1995.

The gas for the proposed export would come from pools in British Columbia. The gas would be transported on the Westcoast Energy Inc. ("Westcoast") pipeline system to the international border near Huntingdon, British Columbia and then delivered by Cascade Natural Gas Corporation ("Cascade") to a natural gas-fired cogeneration facility near Ferndale, Washington, owned and operated by Tenaska Washington Partners, L.P. ("TWP").

2.2 Gas Supply

2.2.1 Supply Contracts

Gas supply contracts with other suppliers were not necessary because BP intends to supply the proposed export with gas from its corporate reserves pool in British Columbia. At this time, BP's corporate reserves pool consists of six wells in the Monkman Pass area. The Board notes that the gas purchase agreement between BP, TWP and Tenaska Gas Co. ("Tenaska"), the natural gas aggregator for TWP, includes a corporate supply warranty. This warranty allows BP to supply gas from all of its non-dedicated sources. In the event that BP is unable to meet its gas requirements, BP is required to pay any incremental costs incurred by Tenaska for replacement fuel supplies.

2.2.2 Reserves

Table 2-1 shows that the Board's estimate of established reserves is 32 percent higher than the applied-for volume. If adjusted to account for expected production to 1 November 1993, the Board's estimate of established reserves would be 13 percent higher than the applied-for volume.

Table 2-1
Comparison of Estimates of BP's Established Gas Reserves and Net Potential with the Applied-for Volume

10^6m^3 (Bcf)

	BP	NEB	Applied-for Volume
Established Reserves	3 380 (120)[1]	4 129 (146)[2]	
Net Potential	2 761 (98)[3]		
Total	6 141 (218)	4 129 (146)	3 128 (110)

1 As of 1 November 1993. This estimate includes the established reserves from the a-39-F, c-62-D, c-88-H and c-59-E wells.
2 As of 31 December 1991. The Board's estimate of remaining established reserves would be approximately 582 10^6m^3 (20 Bcf) less than shown if adjusted for estimated production from the period 1 January 1992 to 1 November 1993.
3 Includes those volumes which BP considers to be net potential from the d-33-H, b-90-H and c-59-E wells.

BP submitted estimates of gas reserves from its corporate reserves pool of six wells in the Monkman Pass area of British Columbia. In all of the wells, gas is contained in the Triassic Pardonet - Baldonnel Formations. BP determined that the established reserves from the a-39-F/93-P-3, c-62-D/93-P-5, c-88-H/93-P-4 and c-59-E/93-P-5 wells were sufficient to satisfy the supply requirements for the proposed export. The a-39-F, c-62-D and c-59-E wells were assigned estimates of proven gas reserves using material balance calculations for gas-in-place. Estimates of probable reserves for these wells were determined by the difference of volumetric calculations (as determined by Monte Carlo simulations) minus material balance calculations of gas-in-place. BP indicated that a volumetric estimate of gas reserves was used for the c-88-H well, rather than its own lower estimate based on material balance analysis, since the volumetric estimate conformed with the estimate of the British Columbia Ministry of Energy, Mines and Petroleum Resources ("BCEMPR").

BP also assigned an estimate of net potential of 2 761 10^6m^3 (98 Bcf) including 1 053 10^6m^3 (37 Bcf) from the b-90-H well. Since b-90-H is on production, the Board included this well in its estimate of established reserves. BP considered its estimates of net potential as back-up gas supply for the proposed export. Volumetric estimates of potential were used for the d-33-H and c-59-E wells, derived from Monte Carlo simulations, while the estimate of potential for b-90-H was based on results from material balance analysis. The Monte Carlo simulations used Pardonet-Baldonnel reservoir parameters from all nearby wells and applied a 95 percent confidence level to the assigned volumetric estimates of reserves. These volumetric estimates minus the material balance-based estimates were then identified by BP as estimates of probable reserves and/or net potential.

In its analysis of BP's corporate reserves pool, the Board decided to employ material balance calculations of gas-in-place to determine its estimates of established reserves for the four wells assigned proven reserves by BP and, in addition, the Board included the b-90-H well. The Board recognizes the limited amount of data available to conduct this analysis; however, the nature of these reservoirs is such that a volumetric analysis at this time has more uncertainty.

In summary, the Board's current estimate of established reserves is 32 percent higher than the applied-for volume; however, by November 1993, the Board's estimate will be 13 percent higher after taking account of estimates of expected production.

2.2.3 Productive Capacity

Figure 2-1 compares the Board's and BP's projections of productive capacity with the applied-for volume. BP's projection indicates that four wells (a-39-F, c-62-D, c-59-E and c-88-H) would be capable of meeting its commitments until 2011. The Board's projection suggests that BP would be able to meet its commitments throughout the proposed licence term based on productive capacity of five wells including the b-90-H well which is currently on production. Both the Board's and BP's projections assumed that BP's production would be limited to its annual applied-for volume.

BP indicated that potential shortfalls in productive capacity could be eliminated by the addition of the d-33-H well and potential resources to be developed in the area.

2.3 Market, Commercial Arrangements and Regulatory Status

2.3.1 Market

The export volumes would be used to fuel a 245 MW natural gas-fired cogeneration facility to be constructed, owned and operated by TWP. The cogeneration facility would be located at the BP Exploration & Oil Inc. ("BPOI") refinery near Ferndale, Washington. Natural gas would be the primary fuel and No. 2 fuel oil would be the back-up fuel. The BPOI refinery would be the thermal energy purchaser.

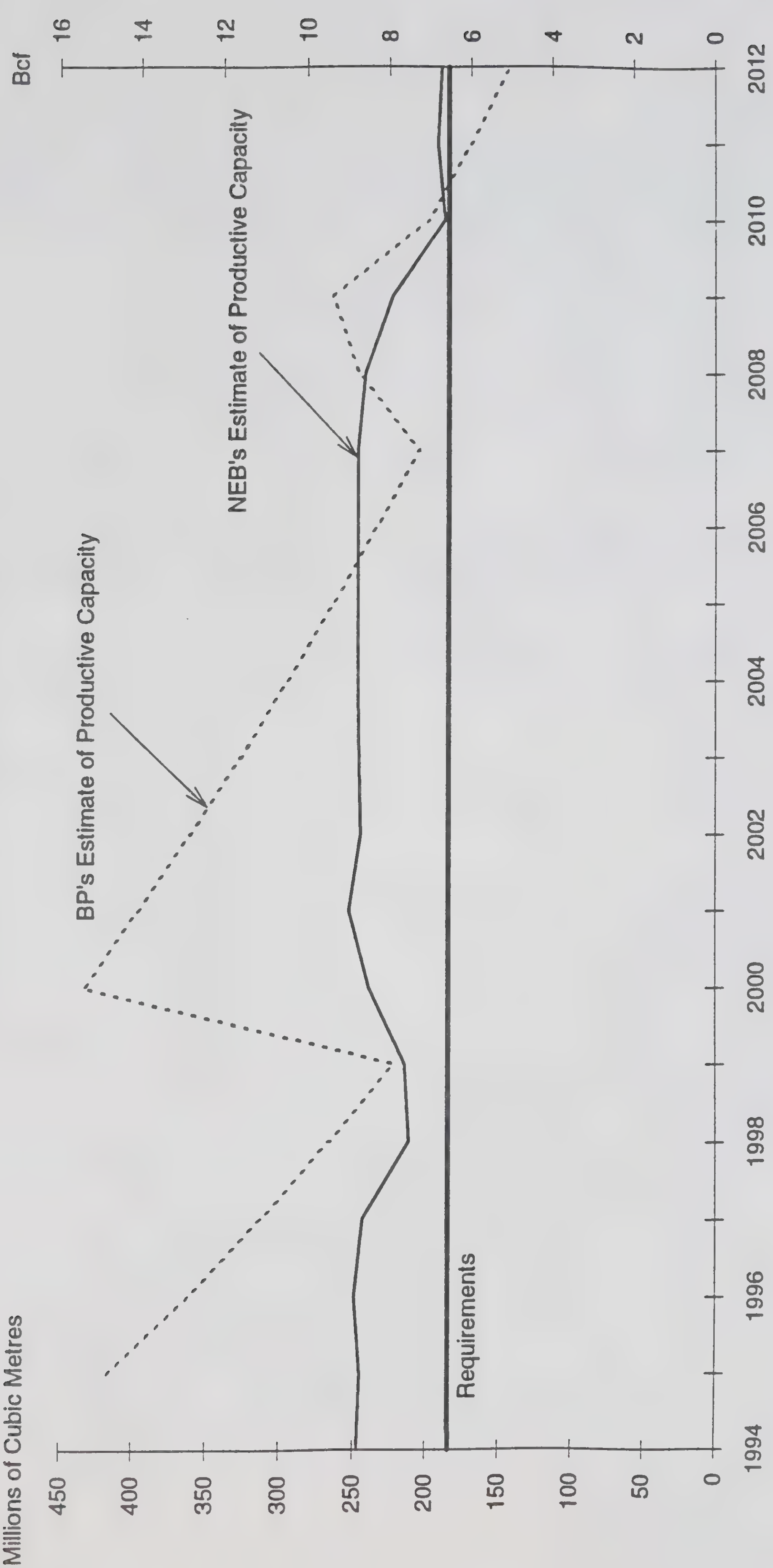
Puget Sound Power & Light Company ("Puget"), the power purchaser, generates, purchases and sells electric power in the northwest United States. Puget serves an estimated population of 1.7 million. Puget's 1990 peak load net capability was approximately 4 743 MW.

The Bonneville Power Administration, a regional power wholesaler, has stated its growing concern of the potential for a regional blackout due to increased power load in the Puget Sound area. Conservation, demand management, electricity imports and new electric generation are all likely to be included in the long-term solution to Puget Sound's potential power shortfall.

At the time of the hearing, TWP expected that it would conclude its project financing with the Chase Manhattan Bank in August 1992. The cogeneration facility is expected to be completed and operational on or about 1 October 1993.

Figure 2-1

Comparison of BP's and NEB's Estimates of Annual Productive Capacity



2.3.2 Transportation

BP has executed a firm service agreement with Westcoast sufficient to deliver the proposed export volumes. BP indicated that its transportation requirements for south mainline capacity would be included in Westcoast's planned 1993 facilities expansion. BP is directly responsible for all transportation charges on Westcoast.

Cascade would transport the gas from the international border to the cogeneration facility under a 20-year firm transportation agreement with Tenaska. Cascade will upgrade its pipeline system and construct two new pipelines to complete the linkage between the international border and the cogeneration facility[1].

2.3.3 Gas Sales Contract

BP, Tenaska and TWP executed a sales agreement ("Sumas agreement") dated 1 August 1992 for sales up to a Daily Contract Quantity ("DCQ") of 504.1 10^3m^3 (17.8 MMcf). Deliveries under the contract would commence no later than 31 October 1995 and continue until the earlier of 31 December of the 17th year following the commencement of commercial operations of the facility or 31 December 2011.

The same parties also signed a complementary sales agreement ("San Juan agreement") dated 1 August 1992. The San Juan agreement would allow BP to obtain gas from Tenaska in the San Juan basin in lieu of payment for gas delivered to the facility under the Sumas agreement if it so chooses.

The Sumas agreement provides for a monthly minimum take of 100 percent of the DCQ times the number of days in the month less any allowable shortfalls. Should TWP not take the full monthly minimum, then it must pay a deficiency charge for volumes not taken. The deficiency charge is calculated as being equal to the greater of either 10 percent of the contract price or the difference between the contract price and the price for gas deliveries to Northwest Pipeline Corp. at the Canadian border as published in *Inside F.E.R.C.'s Gas Market Report* ("Inside F.E.R.C.").

The contract price under the Sumas agreement would be the value set for El Paso Natural Gas Co. ("El Paso") purchases from the San Juan basin as published in Inside F.E.R.C. BP submitted that the contract price would be more than adequate to cover its costs. If the price quotation for El Paso ceased to exist, the parties would cooperate to establish a new price under the Rules of the British Columbia International Commercial Arbitration Centre.

BP estimated that the price that would have been in effect under the terms of the Sumas agreement at the British Columbia border on 1 January 1992 was $Cdn. 1.87/GJ ($Cdn. 1.97/MMBtu).

The two sales agreements are subject to the completion of all necessary contractual arrangements and the receipt of all regulatory approvals by 31 March 1993. BP expects that 50 percent of the sales proceeds under the Sumas agreement would be in the form of gas delivered to BP in the San Juan basin under the San Juan agreement. BP stated that both contracts were negotiated at arm's length.

BP estimated that the load factor for the proposed export would be approximately 90 percent over the term of the Sumas agreement.

---

1 The Board notes that FERC approval to construct a three-mile pipeline segment to transport gas for Tenaska was granted by FERC Order CP91-2650.

2.3.4 Power Purchase Agreement

The sale of electricity from the cogeneration facility would be pursuant to the Agreement for Firm Power Purchase, dated 20 March 1991, between TWP and Puget. The agreement expires the earlier of 31 December of the 17th year after the commercial operation date or on 31 December 2011. The agreement may be extended for up to eight years. A redacted copy of the power purchase agreement was filed with the Board. The Washington Utilities and Transportation Commission has approved the agreement.

The purchase agreement was structured to have the cogeneration plant operate at as high a capacity factor as possible. Maximum available capacity from the cogeneration plant is 245 MW; however, purchases are expected to average 215 MW over a year. The energy capability is limited to an average of 215 MW to allow Puget to coordinate the cogeneration facility's output with the utility's hydroelectric operations.

The price of electricity is negotiated and may differ from the rate that PURPA would otherwise require. The price incorporates a partially levelized rate that results in a contract price exceeding non-levelized rates during certain portions of the operating period. Puget may reduce purchases during May due to decreased demand and increased supply from hydraulic sources. Accordingly, facility maintenance will be conducted in May. Puget will design, own and upgrade the transmission line required to interconnect with the cogeneration facility.

2.3.5 Thermal Energy Sales Agreement

The sale of thermal energy from the cogeneration facility would be pursuant to the Steam Agreement executed 28 August 1992 between TWP and BPOI.

The BPOI refinery has a steam load exceeding the minimum load needed to qualify as a PURPA QF. The proposed minimum steam deliveries would ensure the maintenance of the cogeneration facility's QF status. Steam sales would be priced below BPOI's avoided steam costs to provide the refinery with an economic incentive to take the thermal energy.

2.3.6 Regulatory Status

By application dated 20 May 1992, BP applied for energy removal authorization from the BCEMPR. Tenaska applied on 31 March 1992 for an import authorization from the U.S. Department of Energy/Office of Fossil Energy ("DOE/FE"). Decisions on these applications are pending. Authorization for the required Westcoast facilities expansion is also outstanding. All other necessary authorizations have been secured for the required pipeline facilities.

2.4 Views of the Board

The Board's estimate of BP's established reserves exceeds the applied-for volume, and its projection of productive capacity indicates that BP will be able to meet its requirements throughout the term of the proposed licence. In addition, the Board notes that BP has undeveloped lands in the area which could be used to supplement the submitted gas supply. The Board also notes that BP has provided a corporate warranty to backstop the requirements of this proposed export. Thus, the Board is satisfied with BP's gas supply arrangements.

The Board notes that BP's estimate of established reserves includes an estimate of probable reserves which was determined by the Monte Carlo simulation methodology. The Board is of the view that estimates of established reserves should not be derived solely from such statistical methodologies. The Board, however, considers BP's estimates of probable reserves to be reasonable, if categorized as undiscovered potential.

With regard to the undeveloped lands, the Board notes that BP employed Monte Carlo simulations to obtain its estimates of net potential. The Board acknowledges that there appears to be significant undiscovered potential in the Monkman Pass area; however, considering the geological complexity of the area, estimates of undiscovered potential ought to be reflected by a range rather than a single point.

The Board notes that transportation for the proposed export has been arranged. Further, the Board is also satisfied that the terms of the sales contract would recover Canadian transportation costs.

The Board is satisfied with the market supporting the proposed export. The Board notes that the power purchaser, Puget, has a need for additional power to meet the increased demand in its service territory.

In the Board's view, the deficiency payment penalty and the 100 percent monthly minimum take provision would ensure that gas will be taken at high levels under the contract. The Board considers the contracts durable in light of the assured market.

The Board is satisfied that the contractual arrangements between BP and Tenaska/TWP were negotiated at arm's length.

Since BP owns the gas proposed for export, the Board is of the view that producer support is demonstrated by the executed gas sales contract between BP, Tenaska and TWP.

The Board is satisfied that the applied-for licence term is appropriate given the available gas supply and the other supporting contractual arrangements.

Regarding the outstanding regulatory authorizations, the Board is of the view that the applications are well advanced and does not foresee difficulties in this regard.

The Board also finds BP's requested licence condition of a heating conversion factor of 38.62 MJ/m^3 to be acceptable and consistent with the Board's past rulings.

Finally, the Board is of the view that a sunset date of 29 January 1996 is reasonable.

2.5 Decision

The Board has decided to issue a gas export licence to BP, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on 1 October 1993 and shall end on 29 January 1996, unless exports have commenced under the licence on or before 29 January 1996, in which case the term would end on the earlier of the 31st of December of the 17th year following first deliveries or 31 October 2011.

Chapter 3

FSC Resources Limited, Saranac Power Partners, L.P. and Shell Canada Limited

3.1 Application Summary

By application dated 10 June 1992, FSC Resources Limited, Saranac Power Partners, L.P. and Shell Canada Limited (collectively referred to as "Joint Applicants") sought, pursuant to Part VI of the Act, the transfer by FSC of gas export Licence GL-138 to Saranac and Shell. The Joint Applicants also requested that Licence GL-138 be varied so that, *inter alia*, it would contain the following terms and conditions:

Term	- 1 November 1993, or the date of first deliveries, whichever is later, and extending for 15 years.	
Point of Export	- Napierville, Québec	
Maximum Daily Quantity	- 1 445 10^3m^3	(51.0 MMcf)
Maximum Annual Quantity	- 529 10^6m^3	(18.7 Bcf)
Maximum Term Quantity	- 7 125 10^6m^3	(251.5 Bcf)
Tolerances	- 10 percent per day and 2 percent per year.	

In the alternative, Saranac and Shell applied for a new gas export licence with the same terms and conditions as noted above.

The gas for the proposed export would be produced from pools in Alberta owned by or contracted to Shell. The gas would be transported on the NOVA Corporation of Alberta ("NOVA") system for delivery to the TransCanada PipeLines Limited ("TransCanada") inlet near Empress, Alberta. TransCanada would ship the gas to the international border near Napierville, Québec. The gas would then flow on the proposed North Country Gas Pipeline Corporation ("North Country") system for final delivery to the proposed cogeneration facility.

Gas export Licence GL-138 was issued to FSC pursuant to the Board's decision in GH-6-89 to allow gas exports near Napierville, Québec to three proposed cogeneration facilities in Clinton County, New York. Since then, the proposed cogeneration facilities have been consolidated into a single cogeneration plant which would be located at Georgia-Pacific Corporation's ("G-P") paper mill near Plattsburg, New York. The electricity and steam generated would be sold to New York State Electric & Gas Corporation ("NYSEG") and G-P respectively.

In their application, the Joint Applicants indicated that the G-P mill may use a portion of the proposed export volume up to a daily quantity of 42 10^3m^3 (1.5 MMcf/d). During the hearing, the Joint Applicants stated that if the Board chose to issue a new licence to Shell and Saranac for the proposed export rather than transfer and vary Licence GL-138, they would prefer to retain Licence GL-138 for exports to the G-P mill. They suggested reducing the volumes currently authorized for export under Licence GL-138 by the amount included in the new licence. This would result in 85 10^3m^3/d (3.0 MMcf/d) being authorized for export under Licence GL-138. The Joint Applicants stated that while varying the terms in Licence GL-138 to allow for this export would be their preference, they would consent to the revocation of the Licence if the Board found it necessary, in order to avoid the necessity of another public hearing on the matter.

3.2 Gas Supply

3.2.1 Supply Contracts

In order to meet the requirements of this proposed export sale and other sales, Shell will provide gas from its own pools as well as purchase small volumes from other producers. The purchased supply accounts for four percent of Shell's estimate of total supply. Shell has purchased this gas for deliverability purposes until its own unconnected pools are brought onstream.

Shell has executed contracts with seven producers, namely: Grad & Walker Resources Ltd., Drillwest Energy Marketing Inc., Inverness Resources Inc., MLC Oil and Gas Ltd., Paloma Petroleums Ltd., Shaman Energy Corp., and Voyager Energy Inc. The terms of these contracts range from two to seven years with options to renew on a year-to-year basis with the exception of the Inverness Resources Inc. contract which may be renewed every two years.

3.2.2 Reserves

Shell has recently revised its aggregate gas supply portfolio. These revisions include the sale of its reserves in the Progress area, the increase of its working interest in the Caroline Beaverhill Lake pool, the addition of reserves to be decontracted from Western Gas and the purchase of gas from Inverness Resources Inc.

Table 3-1 shows that the Board's estimate of Shell's remaining gas reserves is six percent lower than Shell's estimate and that both estimates are considerably higher than the applied-for volume. The Board notes that the volumes under consideration for this proposed export are only a portion of Shell's total requirements which include eight long-term export sales and two long-term domestic sales. The Board's estimate of Shell's reserves is essentially the same as Shell's total requirements.

In its assessment of the application, the Board has recognized gas reserves in 136 pools located in 39 fields. Shell owns 19 of these pools; the remainder of the pools were contracted from other producers. The majority of the pools are found in Lower Cretaceous horizons whereas most of the reserves are found in a few, very large, Mississippian and Devonian pools. The Board's analysis indicated that 89 pools contain reserves of less than 100 10^6m^3 (3.5 Bcf) and 11 pools contain more than 1 000 10^6m^3 (35 Bcf). Two of these 11 pools contain more than 10 000 10^6m^3 (353 Bcf). The 11 large pools, owned by Shell, represent 85 percent of the net remaining reserves. Approximately 76 pools were on production by 1 January 1992.

Table 3-1

Comparison of Estimates of Shell's Established Gas Reserves with the Applied-for Volume

10^6m^3 (Bcf)

Shell[1]	NEB[1]	Applied-for Volume[2]
41 280 (1 458)[3]	38 880 (1 373)[3]	7 125 (251.6)

1 As of 1 January 1992.

2 These volumes represent only a portion of Shell's total commitments which must be supplied from these reserves. Shell's total commitments, including the applied-for volumes, are 38 498 10^6m^3 (1 360 Bcf).

3 This supply includes 1 642 10^6m^3 (58 Bcf) of purchased gas.

Differences between the Board's and Shell's estimates of reserves for Shell's own pools are found mainly in the Clearwater and Waterton areas. These areas contain reserves in Mississippian thrust fault structures. The Board's estimate of reserves is 13 percent lower than Shell's for Clearwater and 17 percent lower for Waterton. The Board's lower estimates are primarily attributable to the mapping of a smaller pool area and the interpretation of less net pay.

The gas supply which Shell will be decontracting from Western Gas consists of reserves in the Moose Mountain Rundle A and B pools, the Whiskey Creek Rundle A, and Turner Valley 7-35 pools. For these pools, the Board's estimate of reserves is approximately 40 percent lower than Shell's estimate. The Board's lower estimate for these pools is due to the interpretation of net pay based on log analysis and to the Board's mapping of smaller pool areas. Additionally, the Board interpreted a higher gas/water interface for the southern portion of the Moose Mountain Rundle A pool.

The Board accepted Shell's estimate of reserves for the small volumes purchased from other producers.

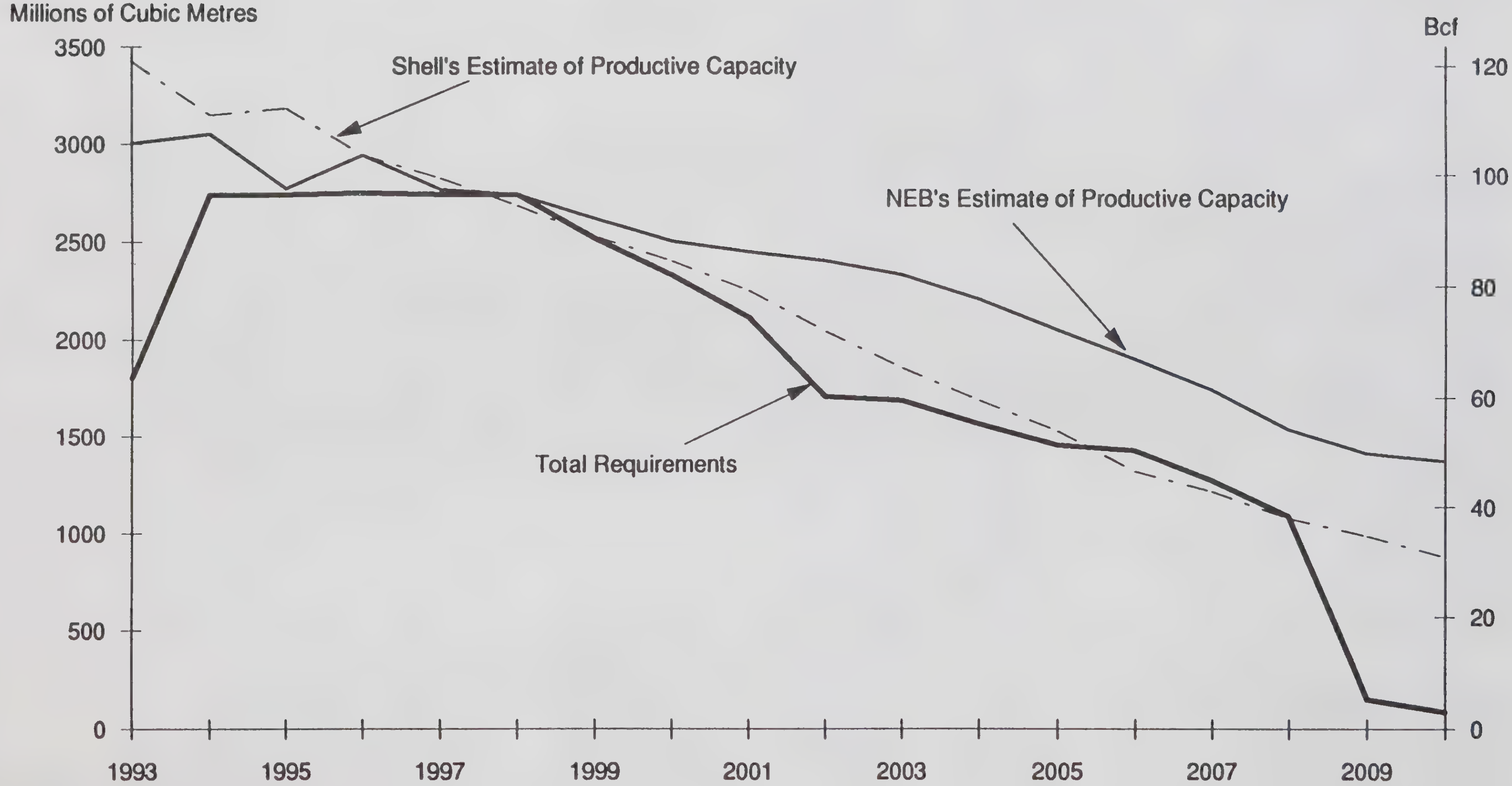
In summary, the Board's estimate of reserves is smaller than Shell's estimate and is essentially the same as Shell's total requirements.

3.2.3 Productive Capacity

Figure 3-1 compares the Board's and Shell's projections of productive capacity with Shell's total requirements, including fuel and shrinkage. Shell has estimated its annual requirements based on expected load factors.

Figure 3-1

Comparison of Shell's & NEB's Estimates of Annual Productive Capacity



Both the Board's and Shell's projections include expected productive capacity from the purchased reserves and additional deliverability of 566 10^3m^3 per day (20 MMcf/d) which Shell can take from the Waterton Field under an agreement with Alberta and Southern Gas Company Ltd. Shell's projection indicates adequate productive capacity with the exception of a minor shortfall between 2006 - 2008. This compares to the Board's projection which shows satisfactory productive capacity throughout the projection period. The difference in outlook is primarily attributable to the Board having adjusted its productive capacity projection to reflect production at a rate equivalent to Shell's annual requirements. Shell suggested that any potential shortfalls in productive capacity would be alleviated by deliverability from other fields it owns, or by purchasing additional gas supplies.

3.3 Market, Commercial Arrangements and Regulatory Status

3.3.1 Market

Shell would be the sole supplier of gas which would be used to fuel a 239.7 MW cogeneration facility. Saranac, the owner and operator of the cogeneration facility, is a Delaware limited partnership and an affiliate of FSC.

The power purchaser, NYSEG, is a regulated electric and gas utility in New York.

The thermal host, G-P's paper mill, manufactures a range of paper-based consumer products. The Joint Applicants stated that Saranac was negotiating a steam sales contract with G-P and expected that the contract would be executed by September 1992.

The cogeneration facility has received QF status from the FERC. Saranac indicated that it anticipates obtaining financing for the cogeneration facility in December 1992. Preliminary construction was expected to commence in September 1992 with major construction activity commencing upon financial closing. The commercial start-up date for the cogeneration facility is expected to be during the first half of 1994.

Saranac expects the cogeneration facility to operate at an average of 90 percent of total capacity over the term of the licence.

3.3.2 Transportation

Within Alberta, the gas would be transported on the NOVA system under Shell's existing and applied-for long-term Firm Service ("FS") capacity. FSC has signed a precedent FS agreement with TransCanada to transport the gas from Empress, Alberta to Napierville, Québec for a period of 15 years. FSC will assign the TransCanada capacity to Shell upon the commencement of commercial operation of the cogeneration facility.

The Napierville Extension, from the TransCanada main line to the export point, is expected to be complete by November 1993. In the United States, gas would flow to the cogeneration facility via the proposed North Country pipeline. Construction of the North Country pipeline is expected to be complete by 1 September 1993.

3.3.3 Sales Contract

Shell and Saranac executed a gas sales contract dated 20 May 1992. The contract term begins with the commencement of commercial operation of the cogeneration facility and continues for 15 years. The contract provides for a DCQ of 51 000 MMBtu (1 445 10^3m^3) and is subject to the completion of all necessary contractual arrangements and the receipt of all regulatory approvals by 1 April 1993. The contract also requires commencement of firm deliveries by 31 March 1995. The Joint Applicants stated that the contract was negotiated at arm's length. The contract does not contain a provision for renegotiation or arbitration of the terms.

The Minimum Annual Quantity ("MAQ") is 80 percent of the product of the DCQ and the number of days in a year, less an adjustment for volumes not delivered or not taken due to plant maintenance or force majeure. If, during the last three years of the contract, Saranac nominates less the MAQ, it is obligated to pay a penalty which is the product of the deficient volume and 11 percent of the weighted average commodity rate. For other contract years, the contract allows Saranac to make up any volumes paid for but not taken during the three-year period immediately following the year in which purchases of gas are less than the MAQ.

Shell is responsible for any incremental costs that Saranac would incur in obtaining replacement fuel for volumes nominated but not delivered by Shell. Shell is also required to utilize its transportation service on NOVA and TransCanada to deliver third party gas to Saranac if needed.

The contract price would be $U.S. 2.97/MMBtu for a period up to and including 31 October 1994 and escalates at a rate of four percent thereafter on each 1 November of the contract year over the term of the contract. The commodity charge is equal to the contract price times the number of days in a month minus the monthly demand charges on NOVA and TransCanada. The Joint Applicants stated that the escalated contract price is expected to compensate for any increases in the transportation levies and to provide an acceptable netback price to Shell.

The estimated netback price that would have been in effect under the terms of this contract at the Alberta border on 1 January 1992 was $Cdn. 2.08/GJ ($Cdn. 2.19/MMBtu).

3.3.4 Power Purchase Agreement

The sale of electricity from the cogeneration facility would be pursuant to the power purchase agreement, dated 27 April 1990, as amended, between NYSEG and Saranac. This agreement will be in effect for a period of 15 years from the commencement of commercial operation at the cogeneration facility. The agreement was approved by the New York Public Service Commission ("NYPSC") subject to conditions. An amendment to the agreement incorporating the conditions was filed with the NYPSC. No further approvals from the NYPSC are needed.

The facility will generate approximately 1,970,000 MW.h. of energy annually, a capacity factor of approximately 90 percent per annum for the 15-year term of the power purchase agreement.

The term of the power purchase agreement has been divided into two periods, A and B, for the purpose of determining the price to be paid for the electricity. Period A pricing will be in effect until 31 December 1995, when period B pricing will commence. Both periods will incorporate peak (class 1) and off-peak (class 2) pricing. During period A, class 1 pricing will be at 6 cents/kW.h. while class 2 pricing will be based on short-run avoided costs. Should the short-run avoided cost tariff as filed with the NYPSC be rescinded, then the avoided cost calculation will incorporate the avoided

costs of production, capacity and transmission. Class 1 and class 2 pricing during period B is a percentage of the NYPSC projection of NYSEG's 1988 long-run avoided costs.

The seller will pay a wheeling charge to NYSEG, to serve as compensation for costs NYSEG may incur to transmit a portion of the facility's output outside NYSEG's Clinton County service territory. Saranac will deliver the electricity to NYSEG directly or to a New York Power Authority ("NYPA") substation which interconnects with the NYSEG power grid. Delivery will be according to the rules and tariffs that govern NYPA.

3.3.5 Thermal Energy Sales Agreement

The Joint Applicants stated that Saranac was pursuing finalization of a steam purchase agreement with G-P and that a copy would be filed with the Board.

3.3.6 Regulatory Status

Shell has applied to the Alberta Energy Resources Conservation Board ("ERCB") to extend the term and increase the volumes authorized under its existing gas removal permit. Saranac applied to the DOE/FE on 9 June 1992 for an import authorization and expected it to be issued by 31 October 1992. All pipeline facilities authorizations have been secured.

3.4 Views of the Board

The Board's estimate of reserves exceeds Shell's total requirements, and the Board's projection of productive capacity suggests that Shell will be able to meet its requirements throughout the term of the proposed licence. The Board is therefore satisfied with the adequacy of Shell's supply relative to its requirements.

The Board notes that transportation has been arranged on all required pipelines. Further, the Board is satisfied that the terms of the gas sales contract ensure that all fixed transportation costs in Canada associated with the export would be recovered.

The Board is satisfied that the downstream markets supporting the proposed export are secure and that the cogeneration facility would operate at a high load factor.

In the Board's view, the contractual provisions regarding deficiency payments, demand charges and Shell's position as the sole supplier ensures gas would be taken at high levels under the gas sales contract. Although the contract contains a fixed price and a price escalator, the Board considers the contract durable in light of the assured markets.

The Board has reviewed the gas sales contract and notes that it has been negotiated at arm's length.

The Board notes that the amended ERCB removal permit and DOE/FE import authorization remain outstanding but the Board does not foresee any difficulties that the Joint Applicants might have in obtaining these authorizations.

To the extent that Shell owns the majority of the submitted gas supply, and has the authority to resell the purchased gas, the Board is of the view that producer support is demonstrated by the executed gas sales contract between Shell and Saranac.

Considering the available gas supply and the fact that the supporting contractual arrangements have terms of 15 years, the Board is satisfied that the applied-for licence term is appropriate.

In the Board's view, it would be preferable for administrative ease to issue a new licence rather than transfer and vary the existing licence in several respects. Regarding the request to amend Licence GL-138 to retain volumes for use by the steam host, the Board is of the view that the Joint Applicants did not provide sufficient evidence to support a licence for G-P's gas requirement.

3.5 Decision

The Board has decided to issue a gas export licence to Saranac and Shell, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on the later of 1 November 1993 or the date of first deliveries and shall end on 1 November 1995, unless exports have commenced under the licence on or before 1 November 1995, in which case the term shall end fifteen years following its commencement.

The Board has also decided to revoke Licence GL-138 effective the date of Governor in Council approval of the new export licence.

Chapter 4

Kamine Beaver Falls Cogen Co., Inc., as managing general partner of Kamine/Besicorp Beaver Falls L.P.

4.1 Application Summary

By application dated 1 June 1992, Kamine Beaver Falls Cogen Co., Inc., as managing general partner of Kamine/Besicorp Beaver Falls L.P., sought pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	-	1 November 1993 to 31 October 2008	
Point of Export	-	near Iroquois, Ontario	
Maximum Daily Quantity	-	456.1 10^3m^3	(16.1 MMcf)
Maximum Annual Quantity	-	167.1 10^6m^3	(5.9 Bcf)
Maximum Term Quantity	-	2 494.9 10^6m^3	(88.1 Bcf)
Tolerance	-	up to 10 percent per day	

Kamine Beaver Falls also requested that the date contained in the sunset clause of the export licence be 29 May 1996. This date would coincide with the expiration of a one-year extension of the 29 May 1995 commencement date of commercial operation of the cogeneration facility.

The gas for the proposed export would be produced from pools in Saskatchewan and Alberta owned by or contractually dedicated to North Canadian Marketing Inc. ("NCM"). The gas would be transported within Alberta on the facilities of NOVA for delivery to the TransCanada system near Empress, Alberta. Saskatchewan-sourced gas would be transported on the TransGas Limited ("TransGas") system to the points of interconnection with TransCanada.

TransCanada would ship the gas to the international border near Iroquois, Ontario. The gas would then flow on the Iroquois Gas Transmission System, L.P. ("Iroquois") and St. Lawrence Gas Company, Inc. ("St. Lawrence Gas") systems for final delivery to the proposed cogeneration facility.

The cogeneration facility would be situated at the site of Specialty Paperboard Inc. ("SPI") at Beaver Falls, New York. Electricity and steam generated at the cogeneration facility would be sold to Niagara Mohawk Power Corporation ("Niagara Mohawk") and SPI, respectively.

4.2 Gas Supply

The following discussion on gas supply applies to both the Kamine Beaver Falls and Kamine Syracuse (collectively referred to as "Kamine") applications. The Kamine Syracuse application is presented in Chapter 5 of these Reasons.

4.2.1 Supply Contracts

Kamine's gas supply for the two applied-for export sales will be provided pursuant to two 15-year natural gas purchase agreements (the "Agreements") with NCM. Although no specific pools have been contractually dedicated to Kamine, NCM submitted a supply pool from which it intends to provide the combined applied-for export volumes. This submitted supply pool will also be used to meet a third requirement, the application by Kamine Natural Dam Cogen Co., Inc., as managing general partner of Kamine/Besicorp Natural Dam L.P. ("Kamine Natural Dam") considered in GH-1-92.

NCM's submitted supply pool consists of its own reserves and gas it has contracted from seven producers; namely, Altex Resources Ltd., Anderson Exploration Ltd., Exchange Resources Ltd., Gardiner Oil & Gas Ltd., Ocelot Energy Inc., Pensionfund Energy Resources Ltd., and Ulster Resources Ltd. These producer contracts constitute approximately 65 percent of NCM's submitted supply; the remainder will be provided by North Canadian Oils Limited ("NCO").

Under the provisions of the Agreements, NCM warrants to deliver the gas nominated by Kamine. In the event NCM is unable to provide the nominated volumes, it will indemnify Kamine against all reasonably incurred incremental costs of obtaining replacement fuel. In addition, NCM's parent company, NCO, has guaranteed certain of the obligations and liabilities of NCM under the gas purchase agreement.

4.2.2 Reserves

Table 4-1 shows that the Board's estimate of Kamine's gas reserves is 12 percent lower than Kamine's estimate, but is more than 50 percent higher than the combined applied-for volumes and 12 percent higher than the total requirements to be met by Kamine's gas supply.

In its analysis of Kamine's gas supply, the Board recognized 130 pools in Alberta and 41 pools in Saskatchewan; only 28 of the 171 pools are currently on production. Alberta pools comprise 64 percent of the total reserves. Most of the pools contain less than 100 10^6m^3 (3.5 Bcf) of initial marketable gas; 35 pools contain reserves of 100 to 1 000 10^6m^3 (3.5 to 35 Bcf) and only six pools contain reserves greater than 1 000 10^6m^3 (35 Bcf). The six largest pools are found in Cretaceous sand deposits.

The Board's lower estimate of reserves can be attributed to a more conservative approach to the interpretation of pool performance studies, to lower estimates of area, net pay, porosity, gas saturation, and recovery factors, and to the interpretation of working interest in certain pools.

Table 4-1

Comparison of Estimates of Kamine's Established Gas Reserves with the Combined Applied-for Volumes

10^6m^3 (Bcf)

Kamine	NEB	Combined Applied-for Volumes
8 643[1] (305.2)	7 624[2] (269.3)	5 000[3] (176.5)

1. As of 1 November 1993
2. As of 31 December 1991. The Board's estimate of remaining reserves would be at least 421 10^6m^3 (15 Bcf) less than shown if further adjusted for estimated production from 1 January 1992 to 1 November 1993. The Board's estimate of reserves would then be 17 percent less than Kamine's, but still 44 percent larger than the combined applied-for volume.
3. In addition to the combined applied-for volumes, Kamine's supply pool will also be used to meet another requirement, the Natural Dam project considered in GH-1-92, for 1 767 10^6m^3 (62 Bcf). The total requirements to be met by the supply pool are therefore 6 767 10^6m^3 (239 Bcf). The Board's estimate of reserves would be six percent greater than the total requirements as of 1 November 1993.

The Board's lower estimates of reserves for the Medicine Lodge Viking A and Knopcik Halfway pools primarily account for the Board's lower estimate of Kamine's total supply.

NCO's Medicine Lodge Viking A pool accounts for 37 percent of the Board's lower estimate of Kamine's total supply. NCO based its estimate on material balance analysis. The Board believes that conducting a material balance at this time is premature since less than ten percent of the pool's estimated reserves have been produced. Therefore, the Board has calculated a volumetric estimate of reserves for this pool. Furthermore, the Board does not agree with NCO's working interest calculation. NCO assumed that there would be no additional drilling or development in the pool and, therefore, most reserves would be captured through the existing wells, including NCO's own well. The Board did not accept NCO's assumption and assigned NCO only ten percent of the pool's reserves.

NCO's Knopcik Halfway pool accounts for 24 percent of the Board's lower estimate of Kamine's total supply. This is primarily attributable to the Board's determination of lower estimates of area, porosity and recovery factor.

In summary, the Board's estimate of reserves is less than Kamine's but it exceeds the combined applied-for volumes. Since Kamine's gas supply will also be used to meet the Kamine Natural Dam requirement, the Board's estimate of remaining reserves will be six percent larger than the total requirements as of 1 November 1993 when expected production is taken into account.

4.2.3 Productive Capacity

A comparison of the Board's and Kamine's projections of productive capacity with Kamine's total requirements is shown in Figure 4-1. Kamine's total requirements include proposed export volumes for the Kamine Beaver Falls and Kamine Syracuse projects, and the Kamine Natural Dam project.

Kamine's projection indicates adequate productive capacity until 2002 with increasing gas supply deficiencies thereafter. The Board's assessment indicates minor gas supply deficiencies between 1998 and 2002. After 2002, the Board's projection of productive capacity is similar to Kamine's projection.

Kamine stated that gas supply shortfalls are unlikely because each producer has provided a corporate warranty to NCM. Each producer is also contractually bound to develop or acquire additional gas supply to meet its gas supply obligation with NCM. In addition, Kamine provided NCO's current corporate supply/demand profile which demonstrates an excess of productive capacity throughout the proposed term.

In addition to the guarantee that NCM has provided to Kamine, NCO has financially guaranteed NCM's obligations to the projects.

4.3 Market, Commercial Arrangements and Regulatory Status

4.3.1 Market

The gas proposed for export would be used to fuel a 79.9 MW natural gas-fired cogeneration facility to be owned and operated by Kamine/Besicorp Beaver Falls L.P.

The power purchaser, Niagara Mohawk, is the second largest public utility in the state of New York. It provides electricity to more than 1.4 million residential, commercial and industrial customers, and has a peak electrical demand exceeding 6 200 MW. Its four major markets are the cities of Buffalo, Syracuse, Albany and Watertown. Watertown is the newest major growth area.

In recent years, Niagara Mohawk's ability to draw power generated by the Power Authority of the State of New York has been reduced annually. Combined with increasing load growth, this has required Niagara Mohawk to seek additional sources of electricity.

Kamine Beaver Falls stated that it expects the cogeneration facility to operate at an average of 92 percent of its total capacity over the life of the project, based on its past experience with other cogeneration projects.

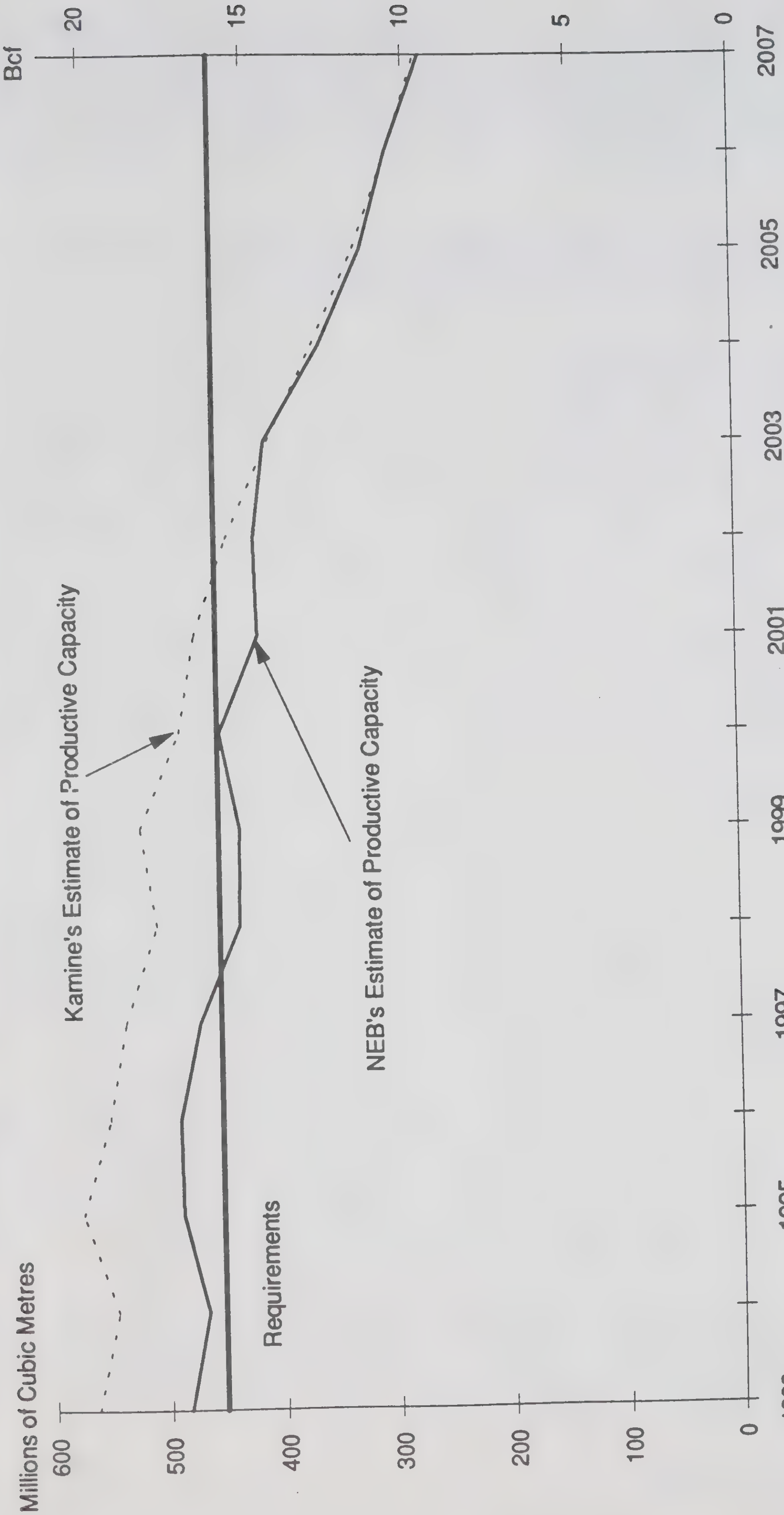
The cogeneration facility will be constructed on a turnkey basis by the contractor.

4.3.2 Transportation

The Alberta gas would be shipped on NOVA for delivery at Empress, Alberta, where Kamine Beaver Falls would take possession of the gas. Gas from Saskatchewan would be transported on TransGas to the point of interconnection with TransCanada, but it will be deemed to have been delivered at Empress, Alberta.

Figure 4-1

Comparison of Kamine's & NEB's Estimates of Annual Productive Capacity



NCM and the producers from whom it has contracted gas have FS transportation arrangements on the NOVA and TransGas systems. Kamine Beaver Falls has signed a precedent FS agreement with TransCanada and precedent Interruptible Service agreements with Iroquois and St. Lawrence Gas for periods ranging from 15 to 25 years. New facilities are required on the TransCanada system and were included in TransCanada's 1993/94 facilities application. Additional facilities are also required on the St. Lawrence Gas system.

Kamine Beaver Falls is directly responsible for all transportation charges on TransCanada. NCM is responsible for paying all NOVA and TransGas charges but can, under the terms of the sales contract, recover any demand charges from Kamine Beaver Falls for volumes not taken.

4.3.3 Gas Sales Contract

NCM and Kamine Beaver Falls have executed a sales contract dated 30 July 1991. The contract term begins 1 November 1993 and ends 1 November 2008. The contract provides for a Maximum Daily Quantity ("MDQ") of 16 MMcf (453.3 10^3m^3) and is subject to the completion of all necessary transportation and financing arrangements and the receipt of all regulatory approvals by 1 November 1993. Kamine Beaver Falls stated that the contract was negotiated at arm's length. There is no provision for renegotiation of the contract.

Kamine Beaver Falls is required to take 80 percent of the MDQ in order to avoid paying the Gas Inventory Charge ("GIC"). The GIC is set at $U.S. 0.38/GJ ($U.S. 0.40/MMBtu) for any volumes below the required gas take. The GIC will be increased in 1994 and thereafter by an amount equal to the annual percentage increase in the producer price index for the northeast United States as published by the U.S. Department of Labour.

Kamine Beaver Falls is obliged to purchase its total gas requirements from NCM.

The contract provides Kamine Beaver Falls with an option to increase or decrease the MDQ by up to ten percent one year after the first gas sale nomination to reflect the cogeneration facility's operating performance. It was stated in evidence that third party sales would be permitted under Kamine Beaver Falls' peak shaving agreement with The Consumers' Gas Company Ltd. to ensure that the export volumes will continue to be taken even in the highly unlikely event of an interruption. Kamine Beaver Falls stated that the contract provides ample evidence that it would buy gas at a high rate of take over the full term of the contract.

The contract price is comprised of a commodity charge and any unabsorbed NOVA demand charges. The commodity charge will escalate over the term of the contract, according to a schedule, for sales up to the MDQ with prices increasing from $U.S. 1.77/GJ ($U.S. 1.86/MMBtu) in 1992 to $U.S. 5.26/GJ ($U.S. 5.54/MMBtu) in 2008. Kamine Beaver Falls stated that the fixed commodity price schedule reflects the parties' reasonable assessment of future gas market conditions compatible with the price of long-term electricity sales to Niagara Mohawk.

Kamine Beaver Falls would pay the unabsorbed demand charges on NOVA which would be equal to 1.2 times the monthly demand charge modified by a factor. The factor takes into account the total volume of gas delivered, volumes nominated but not delivered, and volumes for which NOVA has granted relief from demand charge obligations.

The estimated netback price for sales up to the MDQ that would have been in effect under the terms of this contract at the delivery point on 1 January 1992 was $Cdn. 2.04/GJ ($Cdn. 2.14/MMBtu).

4.3.4 Power Sales Agreement

The proposed sale of electricity from the cogeneration facility would be pursuant to the agreement dated 21 August 1989, as amended, between Kamine Beaver Falls and Niagara Mohawk. The agreement continues for a period of 25 years from the date of commercial operation of the facility and has been approved by the NYPSC.

The cogeneration plant is a must-run facility and is not dispatchable. The price of electricity delivered to Niagara Mohawk will initially be U.S. 6 cents/kW.h. Once certain financial milestones are reached, the price will be calculated at between 90 and 95 percent of Niagara Mohawk's avoided cost.

Curtailment of purchases from the cogeneration facility could occur if Niagara Mohawk is able to produce electricity for less than the cost of purchasing it. However, Niagara Mohawk is required to obtain NYPSC approval for curtailment, and there are no reasonably foreseeable circumstances that could result in curtailment.

4.3.5 Thermal Energy Sales Agreement

The proposed sale of thermal energy would be pursuant to a 25-year agreement between Kamine Beaver Falls and SPI which is summarized in their Term Sheet dated 9 August 1991. Under the agreement, SPI is required to take an amount of steam sufficient for the project to retain its QF status under the rules established by the FERC.

4.3.6 Regulatory Status

NCM applied for removal permits from the ERCB and Saskatchewan Energy and Mines ("SEM") on 28 February 1992 for a term commensurate with the applied-for export licence. SEM has since recommended approval of NCM's application. The ERCB's decision is pending.

Kamine Beaver Falls provided the Board with a copy of the FERC Order, issued on 29 August 1991, granting the facility QF status.

The outstanding U.S. regulatory approvals are from the NYPSC for certification of the additional St. Lawrence Gas facilities, and the DOE/FE for import authorization. The Board's approval of TransCanada's 1993/94 facilities application, which made provision for the delivery of these exports, has now been issued. Kamine Beaver Falls agreed to keep the Board informed of the status of outstanding regulatory applications.

4.4 Views of the Board

The Board notes that although its estimate of Kamine's established reserves exceeds the total requirements to be met by Kamine's gas supply, the Board's projection of productive capacity suggests that shortfalls may commence as early as 1998. However, the Board recognizes that the individual producers have provided corporate warranties to supply their share of the required volumes and have agreed to develop or acquire new gas supplies to meet their requirements. In addition, NCO has provided a separate guarantee for the NCM obligation and has provided a corporate supply/demand balance which shows an excess of productive capacity throughout the contract term. Thus, the Board is satisfied with Kamine's gas supply arrangements.

Kamine Beaver Falls has contracted for transportation on all required pipelines. Furthermore, the Board is satisfied that the terms of the sales contract would recover all fixed transportation costs in Canada.

The Board is also satisfied that the identified markets support the proposed export. The Board notes that the power purchaser, Niagara Mohawk, has experienced an increase in demand for electricity in its service territory in recent years. As well, Kamine Beaver Falls has obtained the QF status for the cogeneration facility.

In the Board's view, the provisions regarding deficiency volume payments and unabsorbed NOVA demand charges ensure gas would be taken at high levels under the sales contract. The Board notes that the commodity price escalates according to a schedule over the term of the licence. The Board is of the view that this contract is durable in light of the assured market.

The Board has reviewed the sales contract and notes it has been negotiated at arm's length.

The Board is satisfied that the applied-for term is appropriate considering the terms of the supporting contractual arrangements and the available gas supply.

The Board notes that the Alberta removal permit, DOE/FE import authorization and NYPSC approval of the proposed St. Lawrence Gas facility are pending. The Board does not foresee difficulties in this regard. The Board further notes that its approval of TransCanada's 1993/94 facilities application, which made provision for the delivery of these exports, has now been issued.

Producer support was evidenced by the fact that the individual producers executed contracts which exclusively dedicated their reserves to NCM for resale to Kamine.

Finally, the Board finds that the request for a sunset date of 29 May 1996 is reasonable.

4.5 Decision

The Board has decided to issue a gas export licence to Kamine Beaver Falls, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on 1 November 1993 and shall end on 29 May 1996, unless exports have commenced under the licence on or before 29 May 1996, in which case the term would end on 31 October 2008.

Kamine Syracuse Cogen Co., Inc., as managing general partner of Kamine/Besicorp Syracuse L.P.

5.1 Application Summary

By application dated 27 April 1992, Kamine Syracuse Cogen Co., Inc., as managing general partner of Kamine/Besicorp Syracuse L.P., sought pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	-	1 November 1993 to 31 October 2008	
Point of Export	-	near Chippawa, Ontario	
Maximum Daily Quantity	-	461.7 10^3m^3	(16.3 MMcf)
Maximum Annual Quantity	-	168.5 10^6m^3	(5.9 Bcf)
Maximum Term Quantity	-	2 506.8 10^6m^3	(88.5 Bcf)
Tolerance	-	10 percent per day	
	-	Any volumes authorized for export which are not actually exported during any year may be exported during the remaining term of the licence.	

The gas for the proposed export would be produced from pools in Saskatchewan and Alberta owned by or contractually dedicated to NCM. The gas would be transported within Alberta on the facilities of NOVA for delivery to the TransCanada system near Empress, Alberta. Saskatchewan-sourced gas would be transported on the TransGas system to the points of interconnection with TransCanada.

TransCanada would ship the gas to the international border near Chippawa, Ontario. The gas would then flow on the Empire State Pipeline ("Empire") and Niagara Mohawk systems for final delivery to the proposed cogeneration facility.

The cogeneration facility would be situated at the site of the New York State Fair ("NYSF") in the village of Solvay, New York. Electricity and steam generated at the facility would be sold to Niagara Mohawk and NYSF, respectively.

5.2 Gas Supply

The gas supply for Kamine Syracuse will be provided by NCM. A description of Kamine's gas supply is provided in Section 4.2 of these Reasons.

5.3 Market, Commercial Arrangements and Regulatory Status

5.3.1 Market

The gas proposed for export would be used to fuel a 79.9 MW natural gas-fired cogeneration facility to be owned and operated by Kamine/Besicorp Syracuse L.P.

The power purchaser, Niagara Mohawk, is the second largest public utility in the state of New York. It provides electricity to more than 1.4 million residential, commercial and industrial customers, and has a peak electrical demand exceeding 6 200 MW. Its four major markets are the cities of Buffalo, Syracuse, Albany and Watertown. Watertown is the newest major growth area.

In recent years, Niagara Mohawk's ability to draw power generated by the Power Authority of the State of New York has been reduced annually. Combined with increasing load growth, this has required Niagara Mohawk to seek additional sources of electricity.

Kamine Syracuse stated that it expects the cogeneration facility's performance to average 92 percent of its capacity over the life of the project based on past experience with cogeneration projects.

Subordinated debt financing has been secured for the project and senior debt financing negotiations have commenced.

5.3.2 Transportation

The Alberta gas would be shipped on NOVA for delivery near Empress, Alberta, where Kamine Syracuse would take possession of the gas. Gas from Saskatchewan would be transported on TransGas to the point of interconnection with TransCanada, but it will be deemed to have been delivered near Empress, Alberta.

NCM and the producers from whom it has contracted gas have FS transportation arrangements on NOVA and TransGas. Kamine Syracuse has signed precedent FS agreements with TransCanada, Empire and Niagara Mohawk for varying periods in excess of 15 years. In its GHR-1-92 Decision, the Board approved TransCanada's Blackhorse Extension which will connect TransCanada's existing system to Empire. Other facilities required on the TransCanada system are included in TransCanada's 1993/94 facilities application.

Kamine Syracuse is directly responsible for all transportation charges on TransCanada. NCM is responsible for all NOVA and TransGas charges but can, under the terms of the sales contract, recover any demand charges from Kamine Syracuse for volumes not taken.

5.3.3 Gas Sales Contract

NCM and Kamine Syracuse executed a sales contract dated 30 July 1991. The contract term begins 1 November 1993 and ends 1 November 2008. The contract provides for an MDQ of 16 MMcf (453.3 10^3m^3) and is subject to the completion of all necessary transportation and financing arrangements and the receipt of all regulatory approvals by 1 November 1993. Kamine Syracuse stated that the contract was negotiated at arm's length. There is no provision for formal renegotiation of the contract.

Kamine Syracuse is required to take 80 percent of the MDQ in order to avoid paying the GIC which is set at $U.S. 0.38/GJ ($U.S. 0.40/MMBtu) for any volumes below the required gas take. The GIC will be increased in 1994 and thereafter by an amount equal to the annual percentage increase in the producer price index for the northeast United States as published by the U.S. Department of Labour.

Between 1 November 1993 and 1 November 1994, Kamine Syracuse has the option to increase or decrease the MDQ by up to ten percent to reflect the cogeneration facility's operating performance. The contract also provides for third party sales of gas quantities up to the MDQ to increase the load factor for the proposed export. Kamine Syracuse stated that the contract provides ample evidence that it would buy gas at a high rate of take over the full term of the contract.

The contract price is comprised of a commodity charge and any unabsorbed NOVA demand charges. The commodity charge will escalate over the term of the contract, according to a schedule, for gas sales up to the MDQ with prices increasing from $U.S. 1.77/GJ ($U.S. 1.86/MMBtu) in 1992 to $U.S. 5.26/GJ ($U.S. 5.54/MMBtu) in 2008. Kamine Syracuse stated that the commodity price schedule reflects the parties' reasonable assessment of future gas market conditions compatible with the price of long-term electricity sales to Niagara Mohawk.

Kamine Syracuse would pay the unabsorbed demand charges on NOVA which would be equal to 1.2 times the monthly demand charge modified by a factor. The factor takes into account the total volume of gas delivered, volumes nominated but not delivered, and volumes for which NOVA has granted relief from demand charge obligations.

The estimated netback price for sales up to the MDQ that would have been in effect under the terms of this contract at the delivery point on 1 January 1992 was $Cdn. 2.04/GJ ($Cdn. 2.14 MMBtu).

5.3.4 Power Sales Agreement

The proposed sale of electricity from the cogeneration facility to Niagara Mohawk would be pursuant to the agreement dated 4 December 1987. The agreement continues for a period of 25 years from the date of commercial operation of the facility, and has been approved by the NYPSC.

The cogeneration plant is a must-run facility and is not dispatchable. The price of electricity delivered to Niagara Mohawk will initially be U.S. 6 cents/kW.h. Once certain financial milestones are reached, the price will be calculated at between 90 and 95 percent of Niagara Mohawk's avoided cost.

Curtailment of purchases from the cogeneration facility could occur if Niagara Mohawk is able to produce electricity for less than the cost of purchasing it. However, Niagara Mohawk is required to obtain NYPSC approval for curtailment, and there are no reasonably foreseeable circumstances that could result in curtailment.

5.3.5 Thermal Energy Sales Agreement

The proposed sale of thermal energy would be pursuant to the agreement dated 9 August 1991 between Kamine Syracuse and the NYSF. The agreement has a 15-year term, and may be extended at the option of Kamine Syracuse. The NYSF thermal use is sufficient to meet the QF conditions defined by the FERC.

5.3.6 Regulatory Status

NCM applied for energy removal permits required for the proposed export from the ERCB and SEM on 28 February 1992 for a term commensurate with the applied-for export licence. SEM has since recommended approval of NCM's application. The ERCB's decision is pending.

Kamine Syracuse informed the Board that it obtained the cogeneration facility's QF status from the FERC on 13 January 1992. As well, on 8 January 1992, Kamine Syracuse applied for a 15-year import authorization from the DOE/FE.

Empire has obtained approval for its pipeline facilities from the NYPSC.

The Board's approval of TransCanada's 1993/94 facilities application, which made provision for delivery of these exports, has now been issued.

5.4 Views of the Board

The Board notes that although its estimate of Kamine's established reserves exceeds the total requirements to be met by Kamine's gas supply, the Board's projection of productive capacity suggests that shortfalls may commence as early as 1998. However, the Board recognizes that the individual producers have provided corporate warranties to supply their share of the required volumes and have agreed to develop or acquire new gas supplies to meet their requirements. In addition, NCO has provided a separate guarantee for the NCM obligation and has provided a corporate supply/demand balance which shows an excess of productive capacity throughout the contract term. Thus, the Board is satisfied with Kamine's gas supply arrangements.

Kamine Syracuse has contracted for transportation on all required pipelines. Furthermore, the Board is satisfied that the terms of the sales contract would recover Canadian transportation costs.

The Board is also satisfied that the identified markets support the proposed export. The Board notes that the power purchaser, Niagara Mohawk, has experienced an increase in demand for electricity in its service territory in recent years.

In the Board's view, the provisions regarding deficiency volume payments, unabsorbed NOVA demand charges and NCM's position as the exclusive gas supplier for the facility ensures gas will be taken at high levels under the sales contract. The Board notes that the commodity price escalates according to a schedule over the term of the licence. The Board is of the view that this contract is durable in the light of the assured market.

The Board has reviewed the sales contract and notes that it has been negotiated at arm's length.

The Board notes that the Alberta removal permit and the DOE/FE import authorization are pending. The Board recognizes that these applications are well advanced and does not foresee difficulties in this regard. The Board further notes that its approval of TransCanada's 1993/94 facilities application, which made provision for the delivery of these exports, has now been issued.

Producer support was evidenced by the fact that the individual producers executed contracts which exclusively dedicated their reserves to NCM for resale to Kamine.

The Board is satisfied that the applied-for licence term is appropriate considering the terms of the supporting contractual arrangements and the available gas supply.

With regard to Kamine Syracuse's request for a tolerance which would allow it to carry forward volumes which were authorized for export but not actually exported during any year, the Board, in response to requests from applicants, has historically included daily and annual operating tolerances in order to accommodate divergences due to operational and measurement discrepancies. Tolerances are not intended to be used to make up volumes that were not previously taken. However, the Board is prepared to authorize a two percent annual tolerance instead of that applied for.

5.5 Decision

The Board has decided to issue a gas export licence to Kamine Syracuse, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on 1 November 1993 and shall end on 1 November 1995, unless exports have commenced under the licence on or before 1 November 1995, in which case the term would end on 31 October 2008.

Chapter 6

Western Gas Marketing Limited for Export to Hadson Power Partners of Rensselaer

6.1 Application Summary

By application dated 12 March 1992, Western Gas Marketing Limited sought, pursuant to Part VI of the Act, a licence for the export of natural gas for sale to Hadson Power Partners of Rensselaer with the following terms and conditions:

Term	-	commencing on first deliveries and extending for 15 years thereafter	
Point of Export	-	Niagara Falls, Ontario	
Maximum Daily Quantity	-	509.9 10^3m^3	(18 MMcf)
Maximum Annual Quantity	-	186.6 10^6m^3	(6.6 Bcf)
Maximum Term Quantity	-	2 800 10^6m^3	(98.8 Bcf)
Tolerances	-	10 percent per day and 2 percent per year	

Western Gas requested that the date contained in the sunset clause of the export licence be March 1995. A provision in the power purchase agreement allows the commencement date of commercial operation of the cogeneration facility to be extended from 12 September 1993 to 12 September 1994. At that point, only a failure by Niagara Mohawk to complete the electrical transmission lines could delay commercial operation. Western Gas stated that Niagara Mohawk could complete that stage in six months; hence, Western Gas would prefer a sunset date of March 1995.

The gas to be exported to Hadson would be produced from pools within Alberta. The gas would be transported on NOVA to the Alberta border at Empress. TransCanada would then deliver the gas to the export point, Niagara Falls, Ontario. From the international border, the gas would be shipped by National Fuel Gas Supply Corporation ("National Fuel"), CNG Transmission Corporation ("CNG") and finally Niagara Mohawk for delivery to the cogeneration facility at Rensselaer, New York. Niagara Mohawk would purchase the electricity, and thermal energy would be sold to BASF Corporation ("BASF").

6.2 Gas Supply

The following discussion of gas supply applies to the three Western Gas applications heard in GH-5-92, which are presented in Chapters 6, 7 and 8 of these Reasons.

In support of its applications, Western Gas relied primarily upon the gas supply analysis that was provided to the Board during the GH-5-89 and GH-3-91 proceedings. This analysis was updated to account for revisions to Western Gas' estimates of established reserves and for changes in its portfolio of producer contracts.

The Board's review of Western Gas' supply for these applications is based on the Board's extensive analysis of the supply information provided in the GH-5-89 proceeding. Recognizing that Western Gas' supply situation has remained substantially unchanged, the Board did not consider it necessary to conduct a detailed review of its reserves and productive capacity at this time.

Details of the Board's earlier analysis were provided in the GH-5-89 Reasons for Decision and again in the GH-3-91 Reasons for Decision.

6.2.1 Supply Contracts and Reserves

Western Gas' estimate of established reserves, as of 31 December 1991, is 501 10^9m^3 (17.8 Tcf). The difference between this estimate and the estimate provided in GH-3-91, which is a reduction of 38 10^9m^3 (1.1 Tcf), is primarily attributable to production during 1991 and to minor revisions in estimates of reserves for over 300 pools. The outlook for terminations of producers' supply contracts provided in GH-5-89 has been updated to reflect notices of contract terminations received during 1990 and 1991.

6.2.2 Productive Capacity

Western Gas submitted projections of productive capacity which reflect its most recent estimates of established reserves and the notices of producer contract terminations which had been received at the time of this proceeding. These projections are similar to those provided in GH-5-89.

The Board notes that the effect of adjusting its projection of productive capacity to reflect the updated information on producer contract terminations, minor reductions in domestic requirements and increased requirements for export sales, including the applied-for exports, would be negligible. Therefore, the Board relied upon the analysis of productive capacity it conducted for GH-5-89. At that time the Board concluded that Western Gas' gas supply would be adequate to meet its contractual commitments even if a significant ongoing level of producer contract termination was assumed.

Western Gas stated that Hadson has the same priority access to Western Gas' supply as its other long-term sales. Under its long-term contracts Western Gas is precluded from entering into new sales arrangements, or renewing existing arrangements, if its projection of remaining reserves to production ratio ("RR/P") is less than ten for any year of a five-year projection period. The projection period succeeds each contract year. Western Gas' current estimate for the last year of the projection period is 14.9.

6.3 Market, Commercial Arrangements and Regulatory Status

6.3.1 Market

The gas proposed for export would be purchased by Hadson and used as fuel supply for a 79 MW natural gas-fired cogeneration facility located in Rensselaer, New York. The cogeneration facility would supply electricity to Niagara Mohawk and steam would be purchased by BASF. BASF is a manufacturer of chemical and other specialty products.

The cogeneration facility would be dispatched on an economic basis by Niagara Mohawk. An independent study of the expected dispatch indicates that the plant will operate at 82 percent of capacity in its first year of operation and at an increased rate in later years.

Hadson commenced construction of the project on 2 March 1992 and completed construction loan and term loan financing on 30 June 1992.

Hadson has executed a peak-shaving agreement with Niagara Mohawk under which the gas could be diverted for use on Niagara Mohawk's system during the peak winter period. Contractually, such diversion cannot exceed 35 days per year.

6.3.2 Transportation

The gas proposed for export would be aggregated within Alberta and delivered to Empress under TransCanada's existing transportation arrangements on NOVA. Western Gas would transport the volumes to Niagara Falls, Ontario pursuant to a renewable transportation contract with TransCanada. Hadson would take delivery of the gas at the international border and would transport the gas on National Fuel from the border to Ellisburg, Pennsylvania pursuant to a contract dated 13 January 1992. CNG would deliver the gas from Ellisburg to one or more delivery points on the Niagara Mohawk system. CNG and Hadson executed an agreement dated 1 October 1991 for this transportation service. The gas would then be transported by Niagara Mohawk to the interconnection with the cogeneration facility pursuant to an agreement dated 20 December 1991. Each of the contracts has a term of 20 years.

A number of pipeline facility expansions are required for this export. Niagara Mohawk will construct 2.5 miles of pipeline to connect its system with the cogeneration facility. In addition, National Fuel plans to add compression to increase its throughput to serve Hadson and other new customers. Finally, CNG is expanding its system under the Hudson River in New York and expects construction to be completed in 1993/1994. No new facilities are required on TransCanada.

6.3.3 Gas Sales Contract

Western Gas and Hadson have executed a contract dated 20 September 1990. The term of this contract commences on the later of 1 February 1994 or the date of first deliveries and continues for a term of 15 years. Hadson has the option to extend the contract for an additional five years. The contract is subject to receipt of the necessary Canadian and U.S. regulatory authorizations by 1 September 1993. The contract is also subject to the execution of transportation arrangements downstream of Niagara Falls, Ontario, receipt of construction financing and a commitment for long-term non-recourse financing of the cogeneration facility by 1 September 1992. The transportation and financing arrangements were in place at the time of the hearing.

If it becomes necessary for Hadson to provide additional financial securities, and those securities are not provided, Western Gas may terminate the gas sales contract. As well, either party can terminate the contract if commercial operation has not commenced prior to 12 September 1994. Western Gas stated that it is unlikely that this provision would be invoked given that the cogeneration facility is currently under construction.

The DCQ is 509.9 10^3m^3 (18.0 MMcf). Volumes in excess of the DCQ may be purchased on an interruptible basis at prices to be negotiated, subject to existing authorizations.

The contract price consists of three components: a monthly demand charge, a variable transportation charge and a commodity charge. The monthly demand charge is the product of the DCQ times the demand tolls on NOVA and TransCanada, including any applicable incremental delivery pressure charges. The charge is payable regardless of Hadson's actual nominations. The variable transportation charge equals the sum of the NOVA and TransCanada commodity tolls and fuel gas charges.

The commodity charge equals the product of $U.S. 1.44/GJ ($U.S. 1.52/MMBtu) and the commodity escalation factor. The commodity escalation factor is an index comprised of the weighted average prices of No. 6 fuel oil at New York Harbour and natural gas purchased by Niagara Mohawk. The weight assigned to these fuels is determined by Niagara Mohawk's actual fuel use at its power plants. However, the weight assigned to gas cannot be less than 75 percent.

Should Hadson nominate less than the MAQ in any year, then it is required to make a deficiency payment. The deficiency payment is the product of 13 percent of the average commodity charge in effect during the year times the difference between actual nominations and the MAQ. The MAQ increases from 70 percent of the Annual Contract Quantity ("ACQ") in the first year to 85 percent of the ACQ in the fifth and subsequent years.

If commercial operation has not commenced by 1 February 1994, then, for each month Hadson fails to take gas, Hadson is required to pay Western Gas a transportation reservation charge. This charge allows Western Gas to recover 50 percent of the TransCanada demand toll from Hadson until the commencement date of commercial operation.

Western Gas estimated that the price under the terms of this contract at the Alberta border on 1 January 1992 would have been $Cdn. 1.72/GJ ($Cdn. 1.81/MMBtu).

The commodity charge and the price index may be renegotiated at the request of either party on an annual basis. Failure to reach an agreement may result in binding arbitration. Should Niagara Mohawk find that a renegotiated commodity charge is unacceptable, then Hadson and Western Gas must submit to binding arbitration. The purpose of any renegotiation or arbitration would be to arrive at a commodity charge which produces netbacks comparable to those received by Canadian producers under similar long-term contracts, and would also likely result in the cogeneration facility being dispatched at least 7 446 hours annually. The form of the demand and commodity rate structure and the components thereof are not subject to renegotiation or arbitration.

Should Western Gas fail to deliver all volumes nominated, then Hadson may purchase such shortfall from an alternative supplier. Western Gas would compensate Hadson for any incremental costs of the purchase.

6.3.4 Power Purchase Agreement

The proposed sale of electricity from the cogeneration plant would be pursuant to the power purchase agreement, dated 23 December 1987, as amended last on 24 January 1991, between Hadson and Niagara Mohawk. The term of the agreement is 25 years from the date the plant commences commercial operation.

The dispatch of the cogeneration facility would be based on economic criteria and controlled by Niagara Mohawk. The rates Niagara Mohawk would pay Hadson for the electricity would be based on the sum of four components: a capacity payment, an energy payment, a fuel transportation payment, and an operation and maintenance payment. In the event that the FERC rescinds QF certification of the cogeneration facility, Hadson is required to seek approval of the power purchase agreement from the FERC. Also, if QF status is rescinded, the rates paid to Hadson for electricity would be decreased by 15 percent.

The power purchase agreement has been approved by the NYPSC.

6.3.5 Thermal Energy Sales Agreement

The proposed sales of thermal energy would be pursuant to an agreement dated 22 February 1991 between BASF and Hadson. The agreement continues for a period of 15 years following the commencement date of commercial operation of the cogeneration facility. The agreement may be extended up to 30 years, in 5-year increments.

BASF is required to accept, at a minimum, the greater of 110 million pounds of steam or such other annual volume of steam required for the cogeneration facility to maintain its FERC QF status.

6.3.6 Regulatory Status

Import authorization was granted by the DOE/FE on 6 August 1992. The FERC approval of construction on CNG was granted on 13 September 1990 and CNG has applied for an extension of this approval. A decision is pending on an application dated 16 April 1992 to the FERC for additional compression on National Fuel. On 7 July 1992, the NYPSC approved construction of the pipeline interconnection between Niagara Mohawk and the cogeneration facility.

Gas would be removed from Alberta under authority of ERCB removal permit GR 91-9. A finding of producer support was released by the Alberta Petroleum Marketing Commission ("APMC") on 31 July 1991.

6.4 Views of the Board

The Board is satisfied that Western Gas has adequate gas supply to meet its currently contracted domestic and export sales requirements, including the proposed export to Hadson.

The Board notes that transportation has been arranged on all required pipelines. Further, the Board is satisfied that the demand charge component of the price will ensure full recovery of all fixed Canadian transportation costs associated with this export.

The Board believes that the commodity charge pricing structure, based upon the prices of No. 6 fuel oil and natural gas purchased by Niagara Mohawk, would ensure that the commodity charge will remain sensitive to changing market conditions. As well, the Board is of the view that the contractual provisions providing for the payment of demand charges regardless of the level of gas taken, the payment of a reservation fee if gas is taken at levels below 85 percent of the DCQ on an annual basis, plus the competitive nature of the commodity charge would ensure that gas would be taken at high levels under the contract. The Board is of the view that this contract is durable in light of the assured market.

The Board has reviewed the gas contract and notes that it has been negotiated at arm's length.

The Board is satisfied that the applied-for licence term is appropriate considering the terms of the supporting contractual arrangements and the available gas supply.

The Board notes that the required import authorization, provincial removal permit and finding of producer support are in place. As well, applications for the various required pipeline facilities have either been approved or are well advanced.

Finally, the Board is of the view that a sunset date of 31 March 1995 is reasonable.

6.5 Decision

The Board has decided to issue a gas export licence to Western Gas, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on the date of first deliveries and shall end on 31 March 1995, unless exports have commenced under the licence on or before 31 March 1995, in which case the term would end 15 years following the commencement of first deliveries.

Chapter 7

Western Gas Marketing Limited for Export to Michigan Consolidated Gas Company

7.1 Application Summary

By application dated 20 April 1992, Western Gas Marketing Limited sought, pursuant to Part VI of the Act, a licence for the export of natural gas for sale to Michigan Consolidated Gas Company, with the following terms and conditions:

Term	-	1 June 1992 to 31 October 1996
Point of Export	-	Emerson, Manitoba
Maximum Daily Quantity	-	906.5 10^3m^3 (32.0 MMcf)
Maximum Annual Quantity	-	331.8 10^6m^3 (11.7 Bcf)
Maximum Term Quantity	-	1 466 10^6m^3 (51.7 Bcf)
Tolerances	-	10 percent per day and 2 percent per year

The gas to be exported to MichCon would be produced from pools within Alberta. The gas would be transported on NOVA to the Alberta border at Empress. TransCanada would then deliver the gas to the export point, Emerson, Manitoba. From the international border, the gas would be shipped on the facilities of Great Lakes Gas Transmission Limited Partnership ("GLGT") for delivery to various points in MichCon's service area.

7.2 Gas Supply

A description of Western Gas' supply is provided in Section 6.2 of these Reasons.

7.3 Market, Commercial Arrangements and Regulatory Status

7.3.1 Market

The gas proposed for export would be sold to MichCon, a public utility engaged in the transmission, storage and distribution of natural gas, for use as system supply. Gas has been flowing under the contract supporting this application under a short-term export order authorized by the Board.

MichCon's market includes Detroit, Grand Rapids and various other communities. The export would also allow MichCon to serve certain communities, such as Sault Saint Marie, Rudyard and Pellston, to which gas can only be transported via GLGT.

MichCon serves more than one million residential, commercial and industrial customers. Sales are projected to increase from 5 713.7 10^6m^3 (201.7 Bcf) in 1992 to 6 005.7 10^6m^3 (212 Bcf) in 1996, approximately a five percent increase. MichCon attributes this growth to an expected increase in residential customers. An anticipated decline in commercial and industrial sales, due to transfers to "transportation only" service on MichCon, would be more than offset by the expected residential growth.

MichCon obtains its gas supply from a number of different sources and geographic areas. The proposed export represents approximately five percent of MichCon's forecasted total requirements.

MichCon expects that purchases from Western Gas would occur at a 100 percent load factor. This forecast is based upon MichCon's market needs and the supplies for which it has contracted.

7.3.2 Transportation

The gas proposed for export would be aggregated within Alberta and delivered to Empress under TransCanada's existing transportation arrangements on NOVA. Western Gas would transport the volumes to Emerson, Manitoba pursuant to a renewable transportation contract with TransCanada. MichCon would take delivery of the gas at the international border. Firm service for 849.8 $10^3m^3/d$ (30 MMcf/d) of gas on GLGT would be provided pursuant to a contract which expires on 1 November 2011.

No new pipeline facilities would be required for the export.

7.3.3 Gas Sales Contract

Western Gas and MichCon executed a five-year sales contract dated 1 September 1991 for a term commencing 1 November 1991. The DCQ is 849.8 10^3m^3 (30.0 MMcf) but MichCon may purchase up to an additional 56.7 10^3m^3 (2.0 MMcf) on an interruptible basis for its daily fuel gas requirements on GLGT. Western Gas stated that there is a high probability that the interruptible volumes will flow. Western Gas claimed this would be the case since the price for the gas would be at a premium to the spot market and transportation would be available to the extent that its other exports at Emerson would not be flowing at 100 percent load factors. The contract is subject to receipt of all necessary long-term Canadian and U.S. authorizations.

The contract price consists of three components: a monthly demand charge, a commodity charge and a deficiency charge. The monthly demand charge is the product of the NOVA and TransCanada tolls, including any applicable incremental delivery pressure charges, times the DCQ. The charge is payable regardless of MichCon's actual nominations.

The commodity charge is defined as the weighted average index price of Oklahoma and Louisiana gas delivered at Detroit less demand charges on GLGT, TransCanada and NOVA. Weights of 70 and 30 percent are assigned to the volumes from onshore Louisiana and Oklahoma respectively.

Should MichCon fail to purchase 20.4 10^6m^3 (720.0 MMcf) in any month, then it is required to pay a deficiency charge to Western Gas. This charge is the product of 20 percent of the monthly commodity charge times the difference between the purchase obligation and actual nominations.

Western Gas estimated that the price under the terms of this contract at the Alberta border on 1 January 1992 would have been $Cdn. 1.637/GJ ($Cdn. 1.72/MMBtu).

Should Western Gas fail to deliver all volumes nominated, then MichCon may purchase such shortfall from an alternative supplier. Western Gas would compensate MichCon for any incremental costs of the purchase.

7.3.4 Regulatory Status

On 28 February 1992, DOE/FE authorized the import of the subject volumes. Gas would be removed from Alberta under authority of ERCB removal permit GR 91-9.

A finding of producer support was released by the APMC on 25 July 1991.

7.4 Views of the Board

The Board is satisfied that Western Gas has adequate gas supply to meet its currently contracted domestic and export sales requirements, including the proposed export to MichCon.

The Board is also satisfied that the market served by MichCon is a stable long-term market for Canadian gas. In particular, the Board notes that gas has already been flowing under short-term arrangements. As well, Western Gas' sale represents approximately five percent of MichCon's total firm peak day requirements and, therefore, it is unlikely that any decrease in MichCon's demand would be borne wholly by this export.

The Board notes that transportation for the firm and interruptible volumes has been arranged on all necessary pipelines. Further, the Board is satisfied that the demand charge component of the price will ensure full recovery of all fixed Canadian transportation costs associated with this export.

The Board believes that the commodity charge pricing structure, based upon the prices of MichCon's primary alternative supplies, would ensure that the commodity charge will remain sensitive to changing market conditions. As well, the Board is of the view that the contractual provisions providing for the payment of demand charges regardless of the level of gas taken, the payment of a deficiency charge if gas is taken at levels below 80 percent of the DCQ on a monthly basis, plus the market-sensitive nature of the commodity charge would ensure that gas will be taken at consistently high levels under the contract. The Board is of the view that this contract is durable in light of the assured market.

The Board is satisfied that the applied-for licence term is appropriate considering the terms of the supporting contractual arrangements and the available gas supply.

The Board has reviewed the gas sales contract and notes that it has been negotiated at arm's length.

The Board also notes that the required import authorization, provincial removal permit and finding of producer support are in place.

With regard to the interruptible volumes to be used as fuel gas on GLGT, the Board is of the view that these volumes should be licensed given that there is a requirement for the gas and that transportation would generally be available.

Finally, the Board notes that Western Gas has applied for a commencement date of 1 June 1992. Since the Board does not backdate its licences, the applied-for term volume must be adjusted to account for a shorter export term. Assuming a commencement date of 1 January 1993, the Board has reduced the applied-for term volume by 194 10^6m^3 (6.8 Bcf). This volume is the product of the DCQ and the number of days between 1 June 1992 and 1 January 1993. During the hearing Western Gas agreed with the Board's method of calculating this necessary reduction in the applied-for volumes.

7.5 Decision

The Board has decided to issue a gas export licence to Western Gas, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence upon Governor in Council approval and shall end on 1 November 1994, unless exports have commenced under the licence on or before 1 November 1994, in which case the term would end on 31 October 1996.

Western Gas Marketing Limited for Export to Natural Gas Pipeline Company of America

8.1 Application Summary

By application dated 20 May 1992, Western Gas Marketing Limited sought, pursuant to Part VI of the Act, a licence for the export of natural gas for sale to the Natural Gas Pipeline Company of America with the following terms and conditions:

Term	-	1 June 1992 to 31 October 2000
Point of Export	-	Emerson, Manitoba
Maximum Daily Quantity	-	4 853 10^3m^3 (171.3 MMcf)
Maximum Annual Quantity	-	1 776 10^6m^3 (62.7 Bcf)
Maximum Term Quantity	-	14 930 10^6m^3 (527 Bcf)
Tolerances	-	10 percent per day and 2 percent per year

The gas to be exported to NGPL would be produced from pools within Alberta. The gas would be transported on NOVA to the Alberta border at Empress. TransCanada would then deliver the gas to the export point, Emerson, Manitoba. From the international border, the gas would be shipped on GLGT and then ANR Pipeline Company ("ANR") for delivery to NGPL near Chicago, Illinois. NGPL is an interstate pipeline serving the midwestern U.S. and it would use the gas as system supply.

8.2 Gas Supply

A description of Western Gas' supply is provided in Section 6.2 of these Reasons.

8.3 Market, Commercial Arrangements and Regulatory Status

8.3.1 Market

NGPL is an interstate pipeline providing transportation service, storage, and sales of natural gas to other pipelines, producers, marketers, local distribution companies ("LDCs") and end-users in nine midwestern states. NGPL has been purchasing Canadian gas for over 20 years. Purchases of gas by NGPL were historically under an arrangement with GLGT and TransCanada. As a result of GLGT's transition to a "transportation-only" pipeline, NGPL will now purchase gas directly from Western Gas.

Gas has been flowing under the contract supporting this application under a short-term export order authorized by the Board.

In 1991, NGPL delivered approximately 45 300 10^6m^3 (1.6 Tcf), including system sales of more than 8 500 10^6m^3 (300 Bcf) to 34 LDCs and two industrial customers. Based on estimates for 1990, the current mix of customers behind the LDCs is 44 percent residential, 18 percent commercial and 38 percent industrial. Demand in the LDC markets has remained relatively unchanged over the past five years.

Regarding the impact of FERC Order 636 upon its sales, NGPL stated that it intends to remain a marketer of natural gas and anticipated that a substantial number of LDCs would choose not to convert to transportation-only service. As well, NGPL stated that the Western Gas supply is critical to NGPL's delivery obligations to customers on the north end of its system.

NGPL obtains its gas supply from producing areas throughout the U.S. and Canada. The proposed export represents approximately 16 percent of NGPL's current annual sales obligations.

NGPL expects that purchases from Western Gas will occur at an 85 percent load factor. This forecast is based upon the expectation of normal weather conditions, NGPL's continuation as a gas merchant and NGPL's ability to maintain its competitive position in its market.

8.3.2 Transportation

The gas proposed for export would be aggregated within Alberta and delivered to Empress under TransCanada's existing transportation arrangements on NOVA. Western Gas would transport the volumes to Emerson, Manitoba pursuant to a renewable transportation contract with TransCanada. NGPL would take delivery of the gas at the international border and would transport the gas on GLGT pursuant to a contract for a term and volume commensurate with that applied for herein. Firm transportation on ANR from GLGT to NGPL has also been arranged for the full term and volume required.

No new pipeline facilities would be required for the export.

8.3.3 Gas Sales Contract

The primary term of the contract executed by Western Gas and NGPL commenced on 1 April 1991 and continues until 31 October 2000. The contract remains in force after this date for successive one-year terms unless terminated by either party. The DCQ is 4 853.3 10^3m^3 (171.3 MMcf). The contract is subject to receipt of all necessary long-term Canadian and U.S. authorizations.

The contract price consists of three components: a monthly demand charge, a commodity charge and any deficiency payments. The monthly demand charge is the sum of a supply reservation charge of \$U.S. 0.16/m^3 (\$U.S. 4.56/Mcf), the NOVA and TransCanada tolls, including any applicable incremental delivery pressure charges, each multiplied by the DCQ. The charge is payable regardless of NGPL's actual nominations.

The commodity charge is determined by subtracting a transportation differential from a spot reference price. The spot reference price equals the arithmetic average for spot index prices of gas delivered to NGPL in Oklahoma, Louisiana and Texas as reported in Inside F.E.R.C. The transportation differential is \$U.S. 0.30/GJ (\$U.S. 0.32/MMBtu). The differential is intended to represent a portion of the transportation costs incurred in delivering the gas to NGPL's system and is subject to adjustment if these transportation costs change.

Deficiency payments are divided into seasonal and daily deficiency payments. The seasonal commitment quantity is 70 percent of the aggregate DCQ for November through March, and 50 percent for the other months. NGPL is obligated to pay Western Gas \$U.S. 0.007/10^3m^3 (\$U.S. 0.20/Mcf) on the difference between actual nominations and the seasonal commitment quantity should the commitment quantity not be taken.

The daily commitment quantity for December through February is 2 125 10^3m^3 (75 MMcf) and is 1 416 10^3m^3 (50 MMcf) for March through November. NGPL is obligated to pay Western Gas \$U.S. 0.004/10^3m^3 (\$U.S. 0.10/Mcf) on the difference between actual nominations and the daily commitment quantity should the commitment quantity not be taken.

Western Gas estimated that the price under the terms of this contract at a 100 percent load factor at the Alberta border on 1 January 1992 would have been \$Cdn. 1.70/GJ (\$Cdn. 1.80/MMBtu).

Effective 1 November 1995, either party may request a renegotiation of the pricing and purchase commitments. Failure to renegotiate these terms results in the termination of the contract following the end of the fifth contract year. The contract may also be terminated if the action of a Canadian or U.S. regulatory authority materially affects the price negotiated under the contract.

Should Western Gas fail to deliver all volumes nominated, then NGPL may purchase such shortfall from an alternative supplier. Western Gas would compensate NGPL for any incremental costs of the purchase.

8.3.4 Regulatory Status

On 21 March 1991, DOE/FE authorized the import of the subject volumes. Gas would be removed from Alberta under authority of ERCB removal permit GR 91-9.

A finding of producer support was released by the APMC on 17 December 1990.

8.4 Views of the Board

The Board is satisfied that Western Gas has adequate gas supply to meet its currently contracted domestic and export sales requirements, including the proposed export to NGPL.

The Board is also satisfied that the market served by NGPL is a stable long-term market for Canadian gas. The Board notes that NGPL has been purchasing Canadian gas for over 20 years. As well, Western Gas' sale represents approximately 16 percent of NGPL's total annual requirements and, therefore, it is unlikely that any decrease in NGPL's demand would be borne wholly by this export.

The Board notes that transportation has been arranged on all required pipelines. Further, the Board is satisfied that the demand charge component of the price would ensure full recovery of all fixed Canadian transportation costs associated with this export.

The Board believes that the commodity charge pricing structure, based upon the prices of NGPL's primary alternative supplies, would ensure that the commodity charge will remain sensitive to changing market conditions. As well, the Board is of the view that the contractual provisions providing for the payment of demand charges regardless of the level of gas taken, the payment of a reservation fee if gas is taken at levels below the set seasonal and daily amounts, plus the competitive nature of the commodity charge would ensure that gas will be taken at consistently high levels under the contract. The Board is of the view that the contract is durable in light of the assured market.

The Board is satisfied that the applied-for licence term is appropriate considering the terms of the supporting contractual arrangements and the available gas supply.

The Board has reviewed the gas contract and notes that it has been negotiated at arm's length.

As well, the Board notes that the required import authorization, provincial removal permit and finding of producer support are in place.

Finally, the Board notes that Western Gas has applied for a commencement date of 1 June 1992. Since the Board does not backdate its licences, the applied-for term volume must be adjusted to account for a shorter export term. Assuming a commencement date of 1 January 1993, the Board has reduced the applied-for term volume by 1 038 10^6m^3 (36.6 Bcf). This volume is the product of the DCQ and the number of days between 1 June 1992 and 1 January 1993. During the hearing Western Gas agreed with the Board's method of calculating this necessary reduction in the applied-for volumes.

8.5 Decision

The Board has decided to issue a gas export licence to Western Gas, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence upon Governor in Council approval and shall end on 1 November 1994, unless exports have commenced under the licence on or before 1 November 1994, in which case the term would end on 31 October 2000.

Chapter 9

Disposition

The foregoing chapters constitute our Decisions and Reasons for Decision in respect of those applications heard by the Board in the GH-5-92 proceedings.

R. Illing
Presiding Member

A. B. Gilmour
Member

C. Bélanger
Member

Calgary, Alberta
December 1992

Terms and Conditions of the Licences to be Issued

Terms and Conditions of the Licence to be issued to BP Resources Canada Limited

1. The term of this Licence shall commence on 1 October 1993, and shall end on 29 January 1996 unless exports commence hereunder on or before 29 January 1996, in which case the term will end the earlier of the 31st of December of the 17th year following first deliveries or 31 October 2011.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 504 140 cubic metres in any one day;

   (b) 184 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 3 128 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

   (c) As a tolerance, the amount that may be exported under the authority of this Licence may vary from the annual limitations imposed in Condition 2 as necessitated by variation in the actual heating conversion factor from the heating conversion factor of 38.62 MJ/m^3 upon which the licensed volumes are based.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Huntingdon, British Columbia.

Terms and Conditions of the Licence to be Issued to Saranac Power Partners L.P. and Shell Canada Limited

1. The term of this Licence shall commence on 1 November 1993 or the date of first deliveries, whichever is later, and shall end on 1 November 1995 unless exports commence hereunder on or before 1 November 1995, in which case the term will end 15 years following commencement of the term of this Licence.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 1 445 000 cubic metres in any one day;

   (b) 529 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 7 125 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Napierville, Québec.

Terms and Conditions of the Licence to be Issued to Kamine Beaver Falls Cogen Co., Inc., as managing general partner of Kamine/Besicorp Beaver Falls L.P.

1. The term of this Licence shall commence on 1 November 1993, and shall end on 29 May 1996 unless exports commence hereunder on or before 29 May 1996, in which case the term will end on 31 October 2008.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 456 100 cubic metres in any one day;

   (b) 167 100 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 2 494 900 000 cubic metres during the term of this Licence.

3. As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Iroquois, Ontario.

Terms and Conditions of the Licence to be Issued to Kamine Syracuse Cogen Co., Inc., as managing general partner of Kamine/Besicorp Syracuse L.P.

1. The term of this Licence shall commence on 1 November 1993, and shall end on 1 November 1995 unless exports commence hereunder on or before November 1 1995, in which case the term will end on 31 October 2008.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 461 700 cubic metres in any one day;

   (b) 168 500 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 2 506 800 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Chippawa, Ontario.

Terms and Conditions of the Licence to be Issued to Western Gas Marketing Limited for Export to Hadson Power Partners of Rensselaer

1. The term of this Licence shall commence on the date of first deliveries, and shall end on 31 March 1995 unless exports commence hereunder on or before 31 March 1995, in which case the term will end 15 years following the commencement of the term of this Licence.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 509 900 cubic metres in any one day;

   (b) 186 600 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 2 800 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Niagara Falls, Ontario.

Terms and Conditions of the Licence to be Issued to Western Gas Marketing Limited for Export to Michigan Consolidated Gas Company

1. The term of this Licence shall commence on the date of Governor in Council approval hereof, and shall end on 1 November 1994 unless exports commence hereunder on or before 1 November 1994, in which case the term will end on 31 October 1996.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 906 500 cubic metres in any one day;

   (b) 331 800 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 1 272 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Emerson, Manitoba.

Terms and Conditions of the Licence to be Issued to Western Gas Marketing Limited for Export to Natural Gas Pipeline Company of America

1. The term of this Licence shall commence on the date of Governor in Council approval hereof, and shall end on 1 November 1994 unless exports commence hereunder on or before 1 November 1994, in which case the term will end on 31 October 2000.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 4 853 000 cubic metres in any one day;

   (b) 1 776 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 13 892 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Emerson, Manitoba.